5030-562

California Methanol Assessment

Volume II: Technical Report

R. O'Toole
E. Dutzi
R. Gershman
R. Heft
W. Kalema
D. Maynard

March 1983

Prepared for

Electric Power Research Institute

Energy Resources Conservation and Development Commission,
State of California

through agreements with National Aeronautics and Space Administration,

and

Atlantic Richfield Company
Chevron USA, Inc.
Conoco Coal Development Company
E.I. du Pont de Nemours Co., Inc.
Exxon Research & Engineering Co.
Ford Motor Company
General Motors Corporation
Litton Energy Systems
Pacific Gas & Electric Company
Phillips Petroleum Company
Solar Energy Research Institute,
U.S. Department of Energy
Southern California Edison Company
Sun Company
Texaco, Inc.
United States Synthetic Fuels Corporation

through grants to and agreements with California Institute of Technology

Prepared by

Jet Propulsion Laboratory

and

Division of Chemistry and Chemical Engineering
California Institute of Technology
Pasadena, California

JPL Publication 83-18 (Vol. II)

Prepared by the Jet Propulsion Laboratory, California Institute of Technology with the assistance and sponsorship of a multi-institutional assessment team partly through an agreement with the National Aeronautics and Space Administration and partly through the California Institute of Technology.

(NASA Tasks RE-152, Amendment 297, CEC 500-82-024; RE-152, Amendment 326, EPRI TPS81-795; and Caltech Work Order 91909).

ABSTRACT

A joint effort by the Jet Propulsion Laboratory and the California Institute of Technology Division of Chemistry and Chemical Engineering has brought together sponsors from both the public and private sectors for an analysis of the prospects for methanol use as a fuel in California, primarily for the transportation and stationary application sectors. Increasing optimism in 1982 for a slower rise in oil prices and a more realistic understanding of the costs of methanol production have had a negative effect on methanol viability in the near term (before the year 2000). Methanol was determined to have some promise in the transportation sector, but is not forecasted for large-scale use until beyond the year 2000. Similarly, while alternative use of methanol can have a positive effect on air quality (reducing NO_x, SO_x and other emissions), a best case estimate is for less than 4% reduction in peak ozone by 2000 at realistic neat methanol vehicle adoption rates. Methanol is not likely to be a viable fuel in the stationary application sector because it cannot compete economically with conventional fuels except in very limited cases. On the production end, it was determined that methanol produced from natural gas will continue to dominate supply options through the year 2000, and the present and planned industry capacity is somewhat in excess of all projected needs. Nonsubsidized coal-based methanol cannot compete with conventional feedstocks using current technology, but coal-based methanol has promise in the long term (after the year 2000), providing that industry is willing to take the technical and market risks and that government agencies will help facilitate the environment for methanol.

Given that the prospects for viable major markets (stationary applications and neat fuel in passenger cars) are unlikely in the 1980s and early 1990s, the next steps for methanol are in further experimentation and research of production and utilization technologies, expanded use as an octane enhancer, and selected fleet implementation. In the view of the study, it is not advantageous at this time to establish policies within California that attempt to expand methanol use rapidly as a neat fuel for passenger cars or to induce electric utility use of methanol on a widespread basis.

ACKNOWLEDGMENTS

The original concept for the California Methanol Assessment was developed by Professor William H. Corcoran of Caltech and James Kelley of JPL. They established a relationship among public and private organizations with diverse interests in methanol, thereby enabling the initiation of the California Methanol Assessment. Professor Corcoran was the Principal Investigator for the Assessment until his unexpected death in August 1982. Caltech Professor George Gavalas assumed the role of Principal Investigator and Caltech/JPL Assessment Coordinator. Professor Harry Gray, Chairman of Chemistry and Chemical Engineering at Caltech, provided information and support to Professor Gavalas and the Caltech Assessment Team participants.

A key element of the California Methanol Assessment was the interaction between the Assessment Team and representatives of public and private organizations with diverse methanol interests. The following organizations and individuals comprised the Technical Advisory Group, providing information, advice, and criticism to the Caltech/JPL Assessment Team participants.

Atlantic Richfield Company: Thomas J. Clough, John Siemssen
California State Energy Resources Conservation and Development Commission: Charles Y. Mizutani, Wendy Reid, David Maul, Ken D. Smith
Chevron USA, Inc.: John Leutwyler, Will Danker
Conoco Coal Development Company: Robert G. Jackson, Carla Stone
E.I. du Pont de Nemours and Company, Inc.: John Hannon, Don Moore
Electric Power Research Institute: Seymour Alpert, H. H. Gilman
Exxon Research and Engineering Company: Kariston Moritz, Leonard Bernstein, Terry Kett, Hugh Shannon
Ford Motor Company: Roberta Nichols
General Motors Corporation: Joe Colucci
Litton Energy Systems: Al Baxley
Pacific Gas and Electric Company: David Hovarongkura; Jim Kimball
Phillips Petroleum Company: Donn B. Wimmer
Solar Energy Research Institute: Joe Finegold
Southern California Edision Company: Charles McCarthy, George Clark
Sun Company: Walt Douthit, Dave Barmby
Texaco, Inc.: Carl Cottle, Fred Wilson, Kathy George
United States Synthetic Fuels Corp.: Larry Ruff, Jim Harlan

The California Methanol Assessment was led by Richard P. O'Toole of JPL. The principal JPL authors of the Assessment and the sections of the Technical Report they were responsible for are:

Elisabeth Dutzi: Chapters 3 and 10
Robert Gershman: Chapters 2 and 9
Ronald Heft: Chapters 7 and 8
David Maynard: Chapter 5
Richard O'Toole: Chapter 4 and Summary Report
William Kalema, Caltech: Chapter 6

Supporting JPL Team members included:

Cindy Carlson
Karl Eckman
Joe Ferrall
Jack Harris
Frank Hoehn
Sue Jones
John McCarthy
Lowell Orren
Gerald Voecks
Eugene Warren
Michael Ziman

Also, Dr. Donald Rapp of JPL made a significant contribution to the study by synthesizing and incorporating many of the sponsor comments into the Technical Report from the March Technical Advisory Group meeting. In addition, Gregory McRae and Puvin Pichaichanarong of Caltech provided significant assistance in determining the probable air-quality consequences of methanol utilization.

Alice Dennison of Caltech coordinated the managerial and financial aspects of this joint JPL/Caltech activity. Pamela Hillman of the Caltech Industrial Associates Office assisted in coordinating the initial Technical Advisory Group meeting. Arlene Calvert of JPL was responsible for word processing and assembling the final report. She was assisted by Fran Mulvehill, and Susan Elrod of JPL who prepared graphical materials for the Technical Advisory Group meetings and the final report. Joyce Whitney served as Project Staff Assistant to J. Kelley of JPL and W. Corcoran of Caltech and coordinated the Technical Advisory Group meetings.

CONTENTS

EXECUTIVE SUMMARY 1

1. INTRODUCTION 1-1

2. OVERVIEW OF CALIFORNIA METHANOL ENERGY DELIVERY SYSTEMS . . 2-1

A. INTRODUCTION 2-1
B. DATA COMPILATION AND ANALYSIS 2-1
C. SUMMARY OF RESULTS 2-10
D. REFERENCES 2-13
ADDENDUM: WORKSHEETS 2-14

3. ENERGY FEEDSTOCK SOURCES FOR METHANOL 3-1

A. INTRODUCTION 3-1
B. OVERVIEW 3-3
C. DESCRIPTIONS AND CLASSIFICATION OF RESOURCES 3-4
D. CONCLUSIONS 3-21
E. REFERENCES 3-22

4. METHANOL AND OTHER SYNFUELS: PRODUCTION OPTIONS AND COSTS . 4-1

A. INTRODUCTION 4-1
B. METHANOL PRODUCTION TECHNOLOGIES 4-1
C. SYNTHETIC FUEL ALTERNATIVES 4-42
D. PRODUCTION COST OVERVIEW 4-61
E. TRANSITION PERIOD PRODUCTION OPTIONS 4-77
F. POLICY OPTIONS FOR METHANOL PRODUCTION 4-97
G. CONCLUSIONS 4-99
H. REFERENCES 4-102

5. TRANSPORT, STORAGE, AND DISTRIBUTION 5-1

A. INTRODUCTION 5-1
B. POSSIBLE SCENARIOS 5-1
C. TRANSPORTATION TECHNOLOGY 5-4
D. TRANSPORT COMPARISONS 5-18
E. STORAGE AND DISTRIBUTION 5-21
F. HAZARDS AND PROBLEMS 5-24
G. NEAR-TERM SUPPLY CONCLUSIONS 5-26
H. TRANSITIONAL FACTORS FOR TRANSPORTATION AND DISTRIBUTION TO CALIFORNIA SUBMARKETS 5-28
I. REFERENCES 5-37

6. AIR QUALITY IMPACT OF METHANOL USE IN VEHICLES 6-1

A. INTRODUCTION 6-1
B. ATMOSPHERIC REACTIONS OF HYDROCARBONS 6-1
C. AIR-QUALTIY MODELING CALCULATIONS FOR SOUTH COAST AIR BASIN 6-7
D. IMPACT OF METHANOL USAGE ON CONCENTRATIONS OF SULFUR COMPOUNDS AND PARTICULATES 6-49
E. SUMMARY AND DISCUSSION 6-53
F. CONCLUSIONS 6-59
G. REFERENCES 6-60

7. CHEMICAL METHANOL PRODUCTION AND USE 7-1

A. INTRODUCTION 7-1
B. CONVENTIONAL METHANOL PRODUCTION TECHNOLOGY 7-1
C. PAST AND PRESENT TRENDS IN THE METHANOL MARKET 7-3
D. CURRENT METHANOL DEMAND 7-3
E. PROJECTIONS OF FUTURE METHANOL DEMAND 7-4
F. UNITED STATES METHANOL SUPPLY 7-4
G. WORLD METHANOL SUPPLY 7-5
H. REFERENCES 7-9

8. METHANOL UTILIZATION IN VEHICLES 8-1

A. METHANOL GASOLINE BLENDS 8-2
B. NEAT METHANOL AS A FUEL 8-36
C. EMISSIONS FROM METHANOL-FUELED VEHICLES 8-74
D. METHANOL FUEL POTENTIAL IN MEDIUM- TO HEAVY-DUTY ENGINES 8-80
E. FLEET SALES POTENTIAL FOR METHANOL VEHICLES 8-106
F. SUMMARY OF POTENTIAL METHANOL DEMAND IN CALIFORNIA TRANSPORTATION SUBMARKETS 8-121
G. CONCEPTS FOR FURTHER ANALYSIS 8-124
H. REFERENCES 8-126

9. METHANOL UTILIZATION IN STATIONARY APPLICATIONS 9-1

A. INTRODUCTION 9-1
B. CALIFORNIA STATIONARY ENERGY DEMAND AND SUPPLY 9-1
C. METHANOL UTILIZATION TECHNOLOGIES FOR STATIONARY APPLICATIONS 9-12
D. EVALUATION OF FACTORS INFLUENCING FUEL SELECTION AND FUEL PRICE COMPARISONS 9-42
E. POTENTIAL ROLES FOR METHANOL IN STATIONARY APPLICATIONS 9-61
F. SUMMARY OF BARRIERS AND POLICY CONSIDERATIONS 9-91
G. CONCLUSIONS 9-94
H. REFERENCES 9-96

10. ENVIRONMENTAL AND REGULATORY CONSTRAINTS 10-1

A. OVERVIEW OF APPLICABLE STATUTES AND REGULATIONS 10-1
B. RESOURCE EXTRACTION 10-8
C. METHANOL PRODUCTION 10-13
D. END USES 10-22
E. SYNFUEL COMPARISONS 10-26
F. METHANOL POTENTIAL IN CALIFORNIA AIR QUALITY PLANNING . 10-34
G. CONCLUSIONS 10-47
H. REFERENCES 10-49
ADDENDUM: ENVIRONMENTAL STANDARDS FOR NEW COAL-FIRED POWER PLANTS 10-52

11. BIBLIOGRAPHY 11-1

APPENDIX A: GLOSSARY AND UNITS OF CONVERSION A-1

APPENDIX B: EXHIBIT OF SPONSOR REVIEW COMMENTS B-1

Figures

2-1. OVERVIEW OF METHANOL ENERGY DELIVERY SYSTEMS 2-2

2-2. DETERMINATION OF COMPETITIVENESS 2-4

3-1. CALIFORNIA OIL AND GAS FIELDS 3-7

3-2. CALIFORNIA COAL DEPOSITS 3-8

3-3. SELECTED WESTERN COAL REGIONS 3-14

4-1. LURGI DRY BOTTOM COAL-TO-METHANOL PRODUCTION COSTS SENSITIVITIES 4-11

4-2. COAL-TO-METHANOL PLANT CONFIGURATION 4-13

4-3. SENSITIVITY OF METHANOL PRODUCTION COST TO ECONOMIES OF SCALE 4-21

4-4. TCGP/ICI COAL-TO-METHANOL PRODUCTION COSTS, 5000 ton/day . . 4-23

4-5. REMOTE NATURAL GAS BARGE-MOUNTED PLANT, 3000 ton/day 4-31

4-6. PETROLEUM COKE-TO-METHANOL PRODUCTION COSTS, 2000 ton/day . 4-35

4-7. WOOD-TO-METHANOL PRODUCTION COSTS, 575 ton/day 4-40

4-8. SYNFUEL PRODUCTS FROM COAL 4-43

4-9. 1992 SHALE OIL-TO-GASOLINE PRODUCTION COSTS, 50,000 BPD . . 4-47

4-10. 1992 SNG PRODUCTION COSTS LURGI TECHNOLOGY 4-51

4-11. 1991 MEDIUM Btu GAS PRODUCTION COSTS 4-52

4-12. FISCHER-TROPSCH PRODUCTION COSTS 50,000 BPD GASOLINE EQUIVALENTS 4-56

4-13. TCGP/ICI COAL-TO-METHANOL PRODUCTION COSTS, 21,165 ton/day . 4-57

4-14. COAL-TO-METHANOL-TO-GASOLINE PRODUCTION COSTS, 50,000 BPD . 4-58

4-15. REQUIRED METHANOL PRICES 4-62

4-16. COMPARISON OF METHANOL PRODUCTION COSTS FROM ALTERNATE FEEDSTOCKS 4-71

4-17. 1992 LNG PRODUCTION COSTS FROM REMOTE NATURAL GAS ON BARGE-MOUNTED PLANTS 4-75

4-18. 1987 GULF COAST NATURAL GAS-TO-METHANOL PRODUCTION COSTS IN EXISTING PLANTS 4-76

4-19. SENSITIVITY OF COAL-TO-METHANOL PRODUCTION COSTS TO REQUIRED RATES OF RETURN 4-90

4-20. DELIVERED COSTS OF MARGINAL METHANOL PRODUCERS 4-94

5-1. POSSIBLE METHANOL FEEDSTOCK - PRODUCTION - UTILIZATION SCENARIOS 5-5

5-2. RAILROAD OPERATING IN 1977 5-6

5-3. PIPELINES AND REFINERIES 5-8

5-4. EXISTING ELECTRICAL GENERATING PLANTS - 1981 5-14

5-5. TRANSPORTATION OF CRUDE OIL BY WATER, 1974 5-15
5-6. TRANSPORTATION OF PETROLEUM PRODUCTS BY WATER, 1974 5-16
5-7. WATER TOLERANCE OF FUELS CONTAINING METHANOL AND GTBA . . . 5-29
5-8. OCCURRENCE OF WATER IN GASOLINE DISTRIBUTION SYSTEM TANKS . 5-31
5-9. POSSIBLE WATER CONCENTRATION AND WATER TOLERANCES FOR METHANOL GASOLINE BLENDS 5-32
5-10. GROWTH OF DIESEL OUTLETS IN L.A. COUNTY 5-35
6-1. DEFINITION OF COMPUTATIONAL GRID SYSTEM FOR THE SOUTH COAST AIR BASIN 6-8
6-2. PREDICTED VS. OBSERVED O_3 AND NO_2 CONCENTRATIONS FOR THE PERIOD OF JUNE 26-27, 1974 6-16
6-3. PEAK OZONE CONCENTRATIONS FOR VARIOUS EMISSION LEVELS . . . 6-41
6-4. PLOT OF PEAK OZONE CONCENTRATION VERSUS PERCENTAGE OF HIGHWAY VEHICLES USING METHANOL 6-43
6-5. PLOT OF OZONE CONCENTRATION VS. TIME 6-45
6-6 REDUCTION IN PEAK OZONE AS A FUNCTION OF NO_x EMISSIONS FOR METHANOL VEHICLES 6-46
6-7. SENSITIVITY OF OZONE PEAK TO PROJECTED EMISSIONS FOR HIGHWAY VEHICLES IN THE YEAR 2000 6-47
7-1. U.S. METHANOL DEMAND, 1979 7-3
7-2. U.S. METHANOL DEMAND, 1990 7-5
8-1. EFFECT OF METHANOL ON GASOLINE VAPOR PRESSURE 8-4
8-2. EFFECT OF METHANOL ON FRONT-END VOLATILITY 8-4
8-3. CHANGE IN EMISSIONS CAUSED BY ADDING 10 PERCENT ALCOHOL TO GASOLINE 8-11
8-4. CHANGE IN LEVEL-ROAD-LOAD FUEL ECONOMY CAUSED BY ADDING 10 PERCENT ALCOHOL TO GASOLINE, VOLUME BASIC 8-11
8-5. CHANGE IN LEVEL-ROAD-LOAD FUEL ECONOMY CAUSED BY ADDING 10 PERCENT TO GASOLINE, ENERGY BASIC 8-12
8-6. EFFECTS OF ALCOHOL AND CARBURETION ON ROAD DRIVEABILITY . . 8-13
8-7. EFFECTS OF TEMPERATURE AND METHANOL ON DRIVEABILITY ON CHASSIS DYNAMOMETER, CAR Z 8-14
8-8. EFFECT OF ADDING METHANOL TO GASOLINE ON RESEARCH, MOTOR, AND ROAD OCTANE NUMBERS 8-14
8-9. EFFECT OF OXYGEN CONTENT OF FUEL ON EXHAUST EMISSIONS OF OXIDATION CATALYST VEHICLES 8-17
8-10. FEVI VS AUTOMOTIVE EVAPORATIVE EMISSIONS 8-18
8-11. RELATIONSHIP BETWEEN FLEET AVERAGE EVAPORATIVE EMISSIONS AND FUEL VOLATILITY 8-19
8-12. COLD DRIVEABILITY PERFORMANCE OF MeOH-BA IN A 1974 PINTO (CAL) AT 70°F 8-20

8-13. COLD DRIVEABILITY PERFORMANCE OF MEOH-BA IN A 1974 PINTO (CAL) AT 35° ± 5°F 8-20
8-14. REPRESENTATIVE MTBE PRODUCTION PROCESSES 8-22
8-15. BLENDING REID VAPOR PRESSURE OF OCTANE BLENDING AGENTS . . . 8-27
8-16. OCTANE BLENDING AGENT COST 8-28
8-17. COST OF OCTANE BLENDING AGENT 8-29
8-18. OCTANE NUMBER BARREL COSTS OF OCTANE ENHANCERS AS A FUNCTION OF WEST COAST METHANOL PRICE 8-31
8-19. PRICE DEMAND RELATIONSHIP FOR METHANOL BY CALIFORNIA REFINERS AND BLENDERS 8-32
8-20. OCTANE NUMBER BARREL COST FOR A METHANOL/TBA BLENDING AGENT AS A FUNCTION OF RVP 8-35
8-21. COMPARISON OF BRAKE HORSEPOWER FOR SEVERAL ENGINE INDUCTION SYSTEMS 8-40
8-22. COMPARISON OF INDUSTRIAL THERMAL EFFICIENCY FOR SEVERAL ENGINE INDUCTION SYSTEMS 8-41
8-23. COMPARISON OF COLD-START DRIVEABILITY WITH GASOLINE AND METHANOL 8-42
8-24. EMISSION COMPARISONS FOR GASOLINE AND METHANOL TWO-WAY EXHAUST CATALYST 8-42
8-25. FUEL ECONOMY COMPARISONS FOR GASOLINE AND METHANOL 8-44
8-26. EFFECT OF EQUIVALENCE RATIOS ON COLD-START DRIVEABILITY . . 8-44
8-27. EFFECT OF EQUIVALENCE RATIO ON EXHAUST EMISSIONS 8-45
8-28. EFFECT OF EQUIVALENCE RATIO ON FUEL ECONOMY 8-45
8-29. EFFECT OF RETARDING SPARK TIMING ON EXHAUST EMISSIONS, DRIVEABILITY AND FUEL ECONOMY 8-46
8-30. FUEL ECONOMY EXPECTATION FOR 1986 8-54
8-31. BASELINE VEHICLE VARIABLE FUEL COSTS 8-57
8-32. METHANOL GASOLINE FUEL FACTOR AS A FUNCTION OF EFFICIENCY IMPROVEMENT 8-61
8-33. METHANOL-GASOLINE FUEL FACTOR 1982-1997 8-61
8-34a. METHANOL VEHICLE VARIABLE FUEL COSTS (No Change) 8-63
8-34b. METHANOL VEHICLE VARIABLE FUEL COSTS (Best Guess). 8-63
8-35. METHANOL PERCENT OF NEW CAR SALES (ASSUMED) 8-67
8-36. METHANOL PERCENT OF TOTAL FLEET 8-68
8-37. PERCENT REDUCTION IN GASOLINE DUE TO METHANOL CARS 8-69
8-38. CONCEPTUAL FLOWSHEET 8-71
8-39. DISSOCIATED METHANOL VEHICLE VARIABLE FUEL COSTS 8-73
8-40. VARIATION OF HC, CO, AND NO CONCENTRATION IN THE EXHAUST OF A CONVENTIONAL SI ENGINE, WITH FUEL-AIR EQUIVALENCE RATIO . 8-75

8-41. CROSS-SECTION M.A.N. D2566 FMUH METHANOL ENGINE 8-83
8-42. FULL-LOAD CHARACTERISTICS OF THE M.A.N. D 2566 FMUH METHANOL ENGINE COMPARED WITH DIESEL ENGINE D 2566 MUH . . . 8-84
8-43. BRAKE THERMAL EFFICIENCY OF THE M.A.N. L9204 FM DIESEL ENGINE 8-85
8-44. BRAKE THERMAL EFFICIENCY OF THE M.A.N. L9204 FM METHANOL ENGINE 8-86
8-45. BRAKE THERMAL EFFICIENCY OF THE M.A.N. 2566 FMUH METHANOL ENGINE 8-87
8-46. FUEL CONSUMPTION OF M.A.N. CITY WITH BUS D 2566 FMUH METHANOL ENGINE 8-88
8-47. THIRTEEN-MODE CYCLE RESULTS OF THE M.A.N. D 2566 FMUH METHANOL ENGINE 8-88
8-48. FULL-LOAD CHARACTERISTICS OF THE M.A.N. D 2566 FMUH COMPARED WITH DIESEL ENGINE D 2566 MUH 8-89
8-49. ENERGY FLOW DIAGRAM OF MERCEDES-BENZ M-407 hGO 8-91
8-50. CIRCUIT DIAGRAM MERCEDES-BENZ ALCOHOL GAS ENGINE 8-92
8-51. FUNCTIONAL DIAGRAM OF MERCEDES-BENZ METHANOL DRIVE SYSTEM . 8-93
8-52. COMBUSTION CHAMBER CONFIGURATION OF THE MERCEDES-BENZ M-407 hGO ENGINE 8-94
8-53. COMPARISON OF OPERATING RANGES, MAXIMUM OUTPUTS AND AIR RATIOS OF GASOLINE, LP-GAS, ALCOHOL-GAS AND DIESEL ENGINES . 8-95
8-54. NEW ZEALAND'S PRELIMINARY RESULTS OF THE FUEL CONSUMPTION OF THE MERCEDES-BENZ M-407 hGO ENGINE. 8-96
8-55. FULL-LOAD PERFORMANCE OF THE MERCEDES-BENZ M-407 hGO ENGINE 8-96
8-56. MERCEDES-BENZ RESULTS OF THE B-MODE FTP CYCLE EMISSIONS OF THE M-407 hGO ENGINE 8-97
8-57. TCCS COMBUSTION CONCEPT 8-99
8-58a. UPS 292 SC TCSS ENGINE PART LOAD BRAKE GASOLINE PERFORMANCE AT 2000 RPM 8-101
8-58b. UPS 292 SC TCCS ENGINE PART LOAD BRAKE GASOLINE PERFORMANCE AT 2500 RPM 8-101
8-58c. UPS 292 SC TCSS ENGINE PART LOAD BRAKE GASOLINE PERFORMANCE AT 3000 RPM 8-101
8-59. UPS 292-SC TCSS ENGINE FULL LOAD PERFORMANCE 8-102
8-60. INDICATED SPECIFIC FUEL CONSUMPTION L-163S TCCS ENGINE ON GASOLINE AND METHANOL 8-103
8-61. PART LOAD BRAKE PERFORMANCE UPS-292 SC GASOLINE AND L-163S SINGLE CYLINDER METHANOL 8-104
8-62. POPULATION AND SALES, WESTERN FLEET VEHICLES, 1978 8-111

8-63. FACTORS CONSTRAINING INITIAL SALE OF METHANOL VEHICLES . . . 8-114
8-64. POSSIBLE SALES VOLUMES FOR METHANOL VEHICLES 8-116
9-1. SOUTHERN CALIFORNIA EDISON COMPANY FUEL OIL PIPELINE SYSTEM STORAGE AND DELIVERY FACILITIES 9-9
9-2. HEAT RATE CURVES 9-25
9-3. NO_x O_2 - METHANOL - FUEL OIL - NATURAL GAS FULL LOAD AS INDICATED IN SYMBOLS 9-30
9-4. COMPARISON OF AC POWER SYSTEM EFFICIENCIES 9-36
9-5. FUEL CELL SYSTEM SCHEMATIC 9-37
9-6. REFORMED METHANOL/FUEL CELL SYSTEM 9-39
9-7. BOILER AND COMBUSTION TURBINES PERFORMANCE COMPARISON . . . 9-43
9-8. NEAR-TERM PREMIUM FOR METHANOL IN INCREASING THE UTILIZATION OF CAPACITY AT ORMOND BEACH 9-51
9-9. PREMIUM FOR METHANOL IN INCREASING CAPACITY AT ORMOND BEACH USING 10% DUAL-FUEL FIRING 9-53
9-10. METHANOL TARGET PRICES 9-59
9-11. PHASING-IN OF UTILITY METHANOL USE--AGGRESSIVE DEVELOPMENT . 9-65
9-12. PHASING-IN OF UTILITY METHANOL USE--CAUTIOUS DEVELOPMENT . . 9-66
9-13. MAXIMUM METHANOL USE DURING PHASING-IN PERIOD 9-68
9-14. 1986 BASELINE SCENARIO METHANOL DEMAND IN UTILITIES 9-69
9-15. 1987 BASELINE SCENARIO METHANOL DEMAND IN UTILITIES 9-70
9-16. 1989 BASELINE SCENARIO METHANOL DEMAND IN UTILITIES 9-71
9-17. 1992 BASELINE SCENARIO METHANOL DEMAND IN UTILITIES 9-72
9-18. 1997 BASELINE SCENARIO METHANOL DEMAND IN UTILITIES 9-73
9-19. 1986 HIGH OIL PRICE SCENARIO METHANOL DEMAND IN UTILITIES . 9-74
9-20. 1987 HIGH OIL PRICE SCENARIO METHANOL DEMAND IN UTILITIES . 9-75
9-21. 1989 HIGH OIL PRICE SCENARIO METHANOL DEMAND IN UTILITIES . 9-76
9-22. 1992 HIGH OIL PRICE SCENARIO METHANOL DEMAND IN UTILITIES . 9-77
9-23. 1997 HIGH OIL PRICE SCENARIO METHANOL DEMAND IN UTILITIES . 9-78
9-24. POTENTIAL VALUE OF METHANOL IN SIP EMISSION REDUCTIONS, OFFSETS, AND BUBBLES 9-80
9-25. POTENTIAL VALUE OF METHANOL IN REMOVING POWER PLANT ENVIRONMENTAL RESTRICTIONS 9-81
9-26. POTENTIAL VALUE OF METHANOL IN MEETING NO_x REDUCTION REQUIREMENTS 9-82
9-27. 1992 BASELINE SCENARIO METHANOL DEMAND WITH DUAL-FUEL EFFICIENCY IMPROVEMENT 9-83
9-28. 1987 BASELINE SCENARIO INDUSTRIAL METHANOL DEMAND 9-85

9-29. 1992 BASELINE SCENARIO INDUSTRIAL METHANOL DEMAND 9-86
9-30. 1997 BASELINE SCENARIO INDUSTRIAL METHANOL DEMAND 9-87
9-31. 1987 HIGH OIL PRICE SCENARIO INDUSTRIAL METHANOL DEMAND . . 9-88
9-32. 1992 HIGH OIL PRICE SCENARIO INDUSTRIAL METHANOL DEMAND . . 9-89
9-33. 1997 HIGH OIL PRICE SCENARIO INDUSTRIAL METHANOL DEMAND . . 9-90

Tables

2-1. SYNFUEL ALTERNATIVES 2-7
2-2. METHANOL SUPPLY SUMMARY 2-11
2-3. SUMMARY OF METHANOL DEMAND AND TARGET PRICES 2-12
3-1. POTENTIAL METHANOL RESOURCES FOR CALIFORNIA 3-5
3-2. 1981 ESTIMATED GAS RESERVES IN PACIFIC RIM COUNTRIES 3-11
3-3. ROCKY MOUNTAIN PROVINCE COALS 3-13
3-4. COAL RESOURCE DATA 3-15
4-1. CAPITAL COST ESTIMATES: COAL TO METHANOL 4-3
4-2. RELATIVE WHOLESALE PRODUCT VALUES IN 1992 TO WHOLESALE GASOLINE 4-4
4-3. TOTAL CAPITAL REQUIREMENT (TCR) PER ANNUAL GALLON OF METHANOL OR GASOLINE CAPACITY 4-6
4-4. DRY BOTTOM LURGI COAL-TO-METHANOL PLANT CHARACTERISTICS . . 4-9
4-5. LURGI PLANT COST DATA 4-10
4-6. TEXACO PARTIAL OXIDATION - ICI METHANOL SYNTHESIS PLANT SPECIFICATIONS 4-14
4-7. METHANOL TRANSPORT BY RAIL 4-14
4-8. TCGP/ICI METHANOL PLANT AND OPERATING COST SUMMARY 4-16
4-9. REQUIRED WESTERN COAL FEED RATES (ton/day) 4-15
4-10. SCALING FACTORS BY PLANT SECTION FOR TCGP SCALE-UP FROM 5000 TO 10,000 ton/day 4-19
4-11. BARGE-MOUNTED METHANOL PLANT SPECIFICATIONS 4-28
4-12. METHANOL PLANTS - BARGE-MOUNTED CONCEPT 4-29
4-13. PLANT INVESTMENT ESTIMATES FOR BARGE-MOUNTED METHANOL PLANTS 4-30
4-14. PETROLEUM COKE-TO-METHANOL CAPITAL AND OPERATING COSTS . . . 4-33
4-15. ANALYSIS OF WOOD FEEDSTOCK 4-37
4-16. WOOD-TO-METHANOL PLANT AND OPERATING COST SUMMARY 4-38
4-17. SYNFUEL PLANTS TECHNICAL ASSUMPTIONS 4-44
4-18. SHALE OIL PLANT AND OPERATING COSTS 4-46
4-19. CAPITAL INVESTMENT ESTIMATES FOR COAL GASIFICATION PLANTS. . 4-49

4-20. PLANT INVESTMENT AND OPERATING COSTS FOR COAL GASIFICATION . 4-50
4-21. PLANT AND OPERATING COSTS FOR INDIRECT PROCESSES 4-54
4-22. NEAT METHANOL VERSUS M-GAS REFERENCE CASE COMPARISON 4-59
4-23. METHANOL PRODUCTION AND OPERATING COST SUMMARY 4-64
4-24. SYNFUEL PRODUCTION AND OPERATING COST SUMMARY 4-65
4-25. ECONOMIC ASSUMPTIONS SUMMARY 4-66
4-26. FEEDSTOCK COSTS 4-68
4-27. FINANCING ASSUMPTIONS 4-69
4-28. DEPRECIATION SCHEDULES 4-69
4-29. REFERENCE CASE ASSUMPTIONS 4-70
4-30. METHANOL PRODUCTION COST SUMMARY 4-72
4-31. PLANT GATE SYNFUEL PRODUCTION COST SUMMARY 4-73
4-32. LNG PLANT AND OPERATING COSTS 4-74
4-33. METHANOL PRODUCTION COST FROM REMOTE NATURAL GAS 4-79
4-34. METHANOL FROM ALASKA AND INDONESIA 4-80
4-35. POTENTIAL ERRORS IN SCALING COAL-TO-METHANOL PLANTS 4-81
4-36. DEDICATED PIPELINE CAPACITY FOR METHANOL TRANSPORT 4-82
4-37. NEAR-TERM (1987) PRODUCTION COST COMPARISON FOR COAL-TO-METHANOL CONCEPTS 4-84
4-38. 1987 METHANOL PRODUCTION COSTS FROM CALIFORNIA FEEDSTOCKS . 4-85
4-39. APPROXIMATE CAPITAL COST PER GALLON OF ANNUAL CAPACITY . . . 4-87
4-40. IMPACT OF LOAN GUARANTEES AND PRICE SUPPORTS ON MINIMUM ACCEPTABLE PLANT-GATE METHANOL PRICES 4-89
4-41. IMPACT OF MID-TERM TECHNOLOGY ON COAL-TO-METHANOL PRODUCTION COSTS 4-92
4-42. SENSITIVITY OF 1987 DELIVERED MARGINAL PRODUCTION COST TO REMOTE NATURAL GAS COST 4-95
5-1. LOCATION OF POTENTIAL METHANOL FEEDSTOCKS 5-2
5-2. TRANSPORT MODE CAPABILITIES 5-3
5-3. TRANSPORT MODES FOR POTENTIAL METHANOL FEEDSTOCKS 5-3
5-4. 1977 U.S. COAL TRANSPORTATION 5-20
5-5. 1977 U.S. CRUDE OIL AND REFINED PETROLEUM TRANSPORTATION . . 5-20
5-6. ENERGY INTENSITY BY TRANSPORTATION MODE 5-21
5-7. METHANOL DELIVERY CAPACITY OF VARIOUS TRANSPORT MODES . . . 5-27
5-8. QUANTITY OF METHANOL DELIVERIES REQUIRED BY VARIOUS TRANSPORT MODES FOR NEAR-TERM USAGE 5-27
6-1. PHOTOCHEMICAL REACTIVITY OF ORGANIC COMPOUNDS: RATE CONSTANTS FOR REACTION WITH HYDROXYL RADICAL 6-4
6-2. CHEMICAL MECHANISM USED IN AIR-QUALITY MODEL 6-10

6-3. INVENTORY OF EMISSIONS OF NITROGEN OXIDES IN THE SOUTH COAST AIR BASIN 6-18

6-4. INVENTORY OF EMISSIONS OF REACTIVE ORGANIC COMPOUNDS IN THE SOUTH COAST AIR BASIN 6-20

6-5. EMISSION FACTORS FOR 1981 MODEL-YEAR VEHICLES 6-24

6-6. DETERIORATION RATES FOR 1981 MODEL-YEAR VEHICLES 6-25

6-7. ODOMETER MILEAGE AS A FUNCTION OF VEHICLE AGE 6-26

6-8. AGE DISTRIBUTION OF VEHICLES 6-27

6-9. COMPOSITE EXHAUST EMISSIONS FOR MOTOR VEHICLES, BASED ON DATA OF TABLES 6-5, 6-6, 6-7, AND 6-8 6-28

6-10. EXHAUST EMISSIONS FROM MOTOR VEHICLES IN YEAR 2000 CALCULATION FOR CMAP INVENTORY 6-29

6-11. EVAPORATIVE EMISSIONS FROM MOTOR VEHICLES 6-30

6-12. COMPOSITION OF EXHAUST, REACTIVE ORGANIC EMISSIONS FROM CATALYST-EQUIPPED VEHICLES 6-31

6-13. COMPOSITION OF EVAPORATIVE EMISSIONS FROM LIGHT-DUTY VEHICLES 6-31

6-14. PROJECTED EMISSIONS OF OXIDES OF NITROGEN FROM MOTOR VEHICLES IN YEAR 2000 6-37

6-15. PROJECTED EMISSIONS OF REACTIVE ORGANIC COMPOUNDS FROM MOTOR VEHICLES IN YEAR 2000 6-38

6-16. PROJECTED PETROLEUM-RELATED STATIONARY-SOURCE EMISSIONS IN THE YEAR 2000, REACTIVE ORGANIC COMPOUNDS 6-39

6-17. PROJECTED PETROLEUM-RELATED STATIONARY-SOURCE EMISSIONS IN THE YEAR 2000, OXIDES OF NITROGEN 6-39

6-18. TOTAL EMISSIONS BY REACTIVITY CLASS, FOR DIFFERENT BASE CASES AND METHANOL CASES 6-40

6-19. INVENTORY OF EMISSIONS OF SULFUR OXIDES IN THE YEAR 2000 . . 6-50

6-20. EFFECT OF METHANOL SUBSTITUTION ON AMBIENT CONCENTRATIONS OF SULFUR COMPOUNDS AND PARTICULATES IN THE SOUTH COAST AIR BASIN 6-52

6-21. MAXIMUM CHANGES IN AIR QUALITY DUE TO USE OF METHANOL IN SPARK-IGNITED MOTOR VEHICLES IN SOUTH COAST AIR BASIN IN THE YEAR 2000 6-53

6-22. REFERENCES FOR PHYSICAL IMPACTS OF AIR POLLUTANTS 6-54

7-1. HISTORICAL U.S. METHANOL PRODUCTION AND PRICES 7-2

7-2. U.S. METHANOL PRODUCTION CAPACITY 7-6

7-3. FREE WORLD METHANOL BALANCE 1981-1987 7-7

7-4. FOREIGN METHANOL PRODUCTION - NEW CAPACITY 7-8

8-1. AVERAGE EXHAUST EMISSIONS AND ENERGY CONSUMPTION OF TEST VEHICLES A THROUGH J OPERATING ON COMMERCIAL GASOLINE-BASE FUEL AND METHANOL BLENDS AT 20°, 75°, and 100°F AMBIENT TEMPERATURES 8-9

8-2. EXHAUST ALDEHYDE DETERMINATIONS 8-10
8-3. PAIRED DIFFERENCE TEST - ALL VEHICLES COMBINED 8-15
8-4. FLEET TEST DRIVEABILITY RESULTS 8-21
8-5. U.S. PRODUCERS OF METHYL TERITIARY-BUTYL ETHER 8-24
8-6. CALIFORNIA FLUIDIZED CATALYTIC CRACKING UNITS 8-25
8-7. BLENDING OCTANE NUMBER AND MOLAR WEIGHT OF SELECTED BLENDING AGENTS 8-26
8-8. CALIFORNIA GASOLINE PRODUCTION FORECASTS 8-33
8-9. PROPERTIES OF METHANOL AND GASOLINE 8-36
8-10. EXHAUST AND EVAPORATIVE EMISSIONS TEST RESULTS FOR FLEET ONE PINTOS 8-47
8-11. CITY DRIVING CYCLE AND PRELIMINARY ON-ROAD FUEL ECONOMY RESULTS FOR FLEET ONE PINTOS 8-47
8-12. VEHICLE DRIVEABILITY AND PERFORMANCE DATA 8-49
8-13. PROTOTYPE VOLKSWAGEN OF AMERICA RABBIT FUEL ECONOMY RESULTS 8-50
8-14. VWoA PROTOTYPE RABBIT EMISSION TEST RESULTS COMPARED WITH THE PROGRAM GOALS AND GASOLINE RABBIT TEST RESULTS . . 8-50
8-15. METHANOL PROTOTYPE AND GASOLINE FORD ESCORT FUEL ECONOMY RESULTS 8-51
8-16. EXHAUST AND EVAPORATIVE EMISSION TEST RESULTS FOR FLEET THREE PROTOTYPE VEHICLE 8-51
8-17. BASELINE PERCENT IMPROVEMENT RELATIVE TO 1982 8-53
8-18. CHANGES FROM 1982 BASELINE FOR CONVENTIONAL GASOLINE TECHNOLOGY 8-56
8-19. CONVENTIONAL GASOLINE BASELINE 8-57
8-20. COMPRESSION RATIO ASSUMPTIONS 8-58
8-21. METHANOL EFFICIENCY COMPARED TO GASOLINE BASELINE 8-60
8-22a. OVER-THE-ROAD FUEL COSTS, GASOLINE VERSUS METHANOL (No Change) 8-62
8-22b. OVER-THE-ROAD FUEL COSTS, GASOLINE VERSUS METHANOL (Best Guess) 8-62
8-23. RETAIL METHANOL PRICES AT THE PUMP 8-64
8-24. HIGH PERFORMANCE DOMESTIC SALES IN 1981 8-65
8-25. DISSOCIATED METHANOL EFFICIENCY COMPARED TO GASOLINE BASELINE 8-72
8-26. OVER-THE-ROAD FUEL COST GASOLINE VERSUS DISSOCIATED METHANOL 8-73
8-27. EXHAUST EMISSIONS AS A FUNCTION OF OPERATING VARIABLE FOR METHANOL ENGINE 8-77

8-28. ENGINE TECHNOLOGIES APPROPRIATE FOR MEDIUM- TO HEAVY-DUTY METHANOL APPLICATIONS 8-81
8-29. L-163S TCCS VS. L-141 GASOLINE ACCELERATION COMPARISON, SWRI WT. 3600 lb 8-100
8-30. L-163S TCCS ENGINE/M-151 VEHICLE EXHAUST EMISSIONS (1979 LIGHT DUTY TRUCK/FEDERAL TEST PROCEDURE) 8-100
8-31. UPS-292 SC vs. GMC 292 FUEL ECONOMY COMPARISONS 8-102
8-32. WESTERN REGIONAL FLEET POPULATION FOR 1978 BY SECTOR 8-108
8-33. WESTERN REGIONAL FLEET REPLACEMENT RATES 8-108
8-34. ESTIMATED TOTAL CAR SALES BY FLEET SECTOR FOR 1978 8-109
8-35. ESTIMATED TOTAL LIGHT TRUCK SALES BY FLEET SECTOR FOR WESTERN REGION 8-110
8-36. PURCHASE CRITERIA 8-112
8-37. FACTORS CONSTRAINING SALES OF METHANOL AUTOMOBILES IN THE WESTERN REGION 8-113
8-38. FACTORS CONSTRAINING INITIAL SALES OF METHANOL-FUELD LIGHT TRUCKS 8-114
8-39. AUTOMOBILES PER YEAR (Possible Methanol Car Sales x 1000) . 8-115
8-40. ANNUAL METHANOL LIGHT TRUCK SALES 8-116
8-41. SIZE DISTRIBUTION AND FLEET FUEL ECONOMY FOR WESTERN AUTOMOBILE FLEETS 8-117
8-42. VEHICLE MILES TRAVELED AND FUEL CONSUMPTION FOR WESTERN REGIONAL FLEET VHEICLES 8-118
8-43. POSSIBLE METHANOL DEMAND--AUTOMOBILES 8-119
8-44. POSSIBLE METHANOL DEMAND--LIGHT TRUCKS 8-119
8-45. LIGHT TRUCK MILES TRAVELED AND FUEL CONSUMPTION FOR WESTERN REGIONAL FLEET VHEICLES 8-119
9-1. UTILITY ADOPTED STATEWIDE DEMAND FORECASTS 9-2
9-2. UTILITY RESOURCE PLANS 9-3
9-3. EXISTING OIL- AND GAS-FIRED GENERATING CAPACITY 9-4
9-4. SCE OIL AND GAS FIRING UNITS 9-6
9-5. LADWP OIL AND GAS-FIRED UNITS 9-8
9-6. TOP ENERGY CONSUMING INDUSTRIES IN CALIFORNIA, 1974 9-10
9-7. FUEL CONSUMING PROCESSES IN KEY INDUSTRIES 9-11
9-8. METHANOL GAS TURBINE PERFORMANCE TESTS 9-13
9-9. SCE METHANOL GAS TURBINE PERFORMANCE TESTS 9-14
9-10. NO_x EMISSION LEVELS IN SCE TEST 9-16
9-11. FUEL/AIR RATIOS AND NO_x EMISSIONS AS A FUNCTION OF LOAD . . 9-17

9-12. EFFECT OF WATER INJECTION ON NO_x EMISSIONS FROM METHANOL . . 9-17
9-13. CO EMISSIONS IN SCE TEST 9-18
9-14. COMPARISON OF EMISSIONS FROM WATER INJECTED JET A AND DRY METHANOL 9-18
9-15. COMPARISON OF PROPERTIES OF JET A FUEL AND METHANOL 9-20
9-16. METHANOL BOILER PERFORMANCE TESTS 9-23
9-17. COMPARISON OF BOILER FIRING WITH METHANOL, NATURAL GAS, AND FUEL OIL 9-26
9-18. PERFORMANCE TEST AT NEW ORLEANS PUBLIC SERVICE CORP. FACILITY 9-27
9-19. PERCENTAGE OF TOTAL HEAT REMOVED IN THE RADIATION SECTION OF A FIRETUBE BOILER 9-27
9-20. NO_x EMISSIONS AS LBS/10^6 Btu HEAT RELEASED 9-28
9-21. NO_x EMISSIONS AS PPMV (Corrected to 0% O_2) 9-28
9-22. REPOWERING COST AND PERFORMANCE FOR CONTRA COSTA #6 9-33
9-23. COST COMPARISONS FOR NEW GENERATION OPTIONS 9-35
9-24. ESEA MODEL INPUTS 9-46
9-25. VALUE OF METHANOL IN AVOIDING ENVIRONMENTAL CONTROL COSTS . 9-49
9-26. ENVIRONMENTALLY RESTRICTED POWER PLANTS 9-50
9-27. NO_x EMISSION LIMITS FOR GENERATING SYSTEMS LOCATED WITHIN THE JURISDICTION OF THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT AND VENTURA COUNTY AIR POLLUTION CONTROL DISTRICT 9-55
9-28. NO_x REDUCTION OPTIONS 9-56
9-29. VALUE OF METHANOL AS ALTERNATIVE TO ADDITION OF NO_x EMISSION CONTROL EQUIPMENT 9-57
9-30. BARRIERS AND POLICY OPTIONS 9-92
10-1. FEDERAL LAND MANAGEMENT CONSTRAINTS TO MINING AND SYNFUEL PLANT SITING 10-10
10-2. ANNUAL WATER REQUIREMENTS - 2000 (1,000 acre-feet/year) . . 10-15
10-3. ANNUAL HEALTH RISKS OF A 1-QUAD COAL GASIFICATION INDUSTRY . 10-21
10-4. ENVIRONMENTAL CHANGES DUE TO METHANOL FUELING 10-23
10-5. COMPARATIVE TOXICITY RATINGS 10-25
10-6. ESTIMATED EMISSION FACTORS FOR PRODUCTION AND COMBUSTION OF METHANOL 10-26
10-7. ANNUAL RESOURCE REQUIREMENTS OF SYNTHETIC FUEL ENERGY SYSTEMS (PRODUCING ANNUALLY 63 X 10^{12} Btu OF USEFUL ENERGY OR 30,800 BARRELS OF OIL EQUIVALENT PER DAY) 10-28

10-8. ANNUAL AIR EMISSIONS WITH CONTROLS AND SOLID WASTES FROM SYNTHETIC FUEL ENERGY SYSTEMS (PRODUCING ANNUAL 63 X 10^{12} Btu OF USEFUL ENERGY OR 30,800 BARRELS OF OIL EQUIVALENT PER DAY 10-29

10-9. INDICES OF MAJOR POTENTIAL HEALTH, SAFETY, AND ENVIRONMENTAL IMPACTS FROM UNIT ENERGY SYSTEMS (PRODUCING ANNUALLY 63 X 10^{12} Btu OF USEFUL ENERGY OR 30,800 BARRELS OF OIL EQUIVALENT PER DAY) 10-30

10-10. MAJOR ANNUAL HEALTH AND SAFETY IMPACTS (CASES/YEAR) FROM UNIT ENERGY SYSTEMS (PRODUCING ANNUALLY 63 X 10^{12} Btu OF USEFUL ENERGY OR 30,800 BARRELS OF OIL EQUIVALENT PER DAY) . 10-31

10-11. RELATIVE ASSESSMENT OF ENVIRONMENTAL HAZARDS 10-32

10-12. PRIORITY RANKING OF SYNFUEL PRODUCTS FROM THE STANDPOINT OF ENVIRONMENTAL CONCERNS 10-33

10-13. REQUIRED AND AVAILABLE EMISSION REDUCTIONS TO MEET AIR QUALITY STANDARDS 10-41

10-14. METHANOL FLEET VEHICLE CONVERSION: EMISSION FORECAST AND REDUCTION. 10-44

10-15. POTENTIAL LONG-RANGE ROG EMISSION REDUCTIONS 10-45

10-16. 1982 CALIFORNIA EMISSION STANDARD VS 1982 VW RABBIT METHANOL EMISSIONS 10-47

EXECUTIVE SUMMARY

BACKGROUND

The California Methanol Assessment was organized by the Jet Propulsion Laboratory (JPL) of the California Institute of Technology (Caltech) through an interagency agreement with the National Aeronautics and Space Administration. The 18-month study was a joint effort of JPL and the Caltech Division of Chemistry and Chemical Engineering and was sponsored by various private companies and public agencies that are potential stakeholders in methanol use, production, and distribution. An in-depth analysis was performed of the status and prospects for methanol use as a fuel in California, primarily in the transportation and utility sectors. Technical data were synthesized from ongoing JPL studies, the sponsors, and other sources. The data were then analyzed for California markets to determine the role that methanol can play, the gaps in the current state of knowledge, and the efforts that are warranted to ensure an efficient and appropriate transition into the marketplace.

Methanol has long been used as a chemical and chemical feedstock. The United States currently produces about 3 million tons/year with an energy equivalent of 100 trillion British thermal units (10^{14} Btu). Methanol has many potential benefits as a fuel. On an overall basis, it has been argued that it could be the lowest cost synthetic liquid fuel. The technology exists to produce methanol from the country's extensive coal reserves as well as from peat, petroleum, coke, natural gas, and bioenergy feedstocks. In automotive and some other applications, the performance of methanol is superior per Btu to that of gasoline and other conventional fuels. Widespread methanol use could have a net positive effect on the environment because it is a clean-burning, low-polluting fuel that ostensibly yields lower atmospheric contributions of NO_x and unburned hydrocarbons. Gasoline-fueled vehicles could be built and stationary power plants could be readily adapted to use of methanol. Methanol can be produced from a variety of domestically available feedstocks and used in a variety of applications. In addition, it is noncarcinogenic.

Expanded production of methanol, unlike other synfuels, will require dedicated storage facilities and delivery systems. Thus, because it is not now in general use as a fuel, more extensive methanol use would require either new dedicated delivery systems or conversion of current systems. On a volume basis, methanol has half the energy content of gasoline, so both storage and vehicular tanks would probably need to be increased in size, with some mitigation because of better fuel performance. Although safety and toxicity problems seem to be no greater than those for gasoline, they are different from today's fuels, and their solutions would require additional education and training. Methanol is hydroscopic, but a small fraction of water can be tolerated in its use as a fuel. Also, methanol could be transported in existing pipelines if some adjustments were made for the fuel's greater miscibility, and if batched load delivery systems were set up.

For methanol to become a viable transportation fuel in the long term, both the fuel and automobile industries must participate in a strategy

involving risk on investments that will not be returned quickly. The issue of scale is important, for it has been suggested that:

(1) Methanol must ultimately be made from coal in large (25,000 tons/day or larger) western minemouth plants.

(2) Methanol must be pipelined to end-use markets in high-volume pipelines (50,000 tons/day).

(3) Automobile manufacturers must mass-produce (at least 30,000 vehicles per year at a given company) optimized methanol-fueled vehicles to achieve end-use economies of scale.

(4) Potential private passenger car buyers must see an established fuel distribution network before they will purchase neat methanol-fueled vehicles.

Each of the above points has been evaluated for the California Methanol Assessment to determine if it is a critical element in the viability of methanol as a fuel in California. Once this basic characterization of the methanol fuel system was made, the analysis focused on what could be done as the next step to facilitate an efficient evolution into the marketplace.

The State of California was chosen as a focus for the study because methanol has many potential uses as a fuel for stationary and transportation applications in California. There are unique benefits that could be derived from widespread use of methanol in California because of the State's air-quality problems and its number of potential feedstock sources for methanol. Relative to the use of conventional fuels, use of methanol could reduce the emissions of sulfur dioxide, nitrogen oxide, and reactive hydrocarbons into the atmosphere of California urban centers.

During the past several years, there has been an increase in the number of test programs for vehicles using methanol and methanol/gasoline blends. The State of California has begun fleet tests, and in 1980 the California Energy Commission (CEC) issued a policy resolution on alcohol fuels. Also, utilities and policy-makers in California have shown an interest in methanol's role in the utility sector, where it could have environmental and fuel diversification benefits.

Clearly, methanol has the potential for much greater use as an alternative fuel in California. Caltech and JPL were greatly interested in examining the realities of that potential, and together they were equipped to provide a useful interdisciplinary study of the problems and potentials. JPL's long-term commitment to the national energy program, coupled with the Laboratory's 30-year history as a leader in fuels research for space and other applications, provided unique experience with chemical processes, combustion, engines, turbines, fuel cells, environmental control, safety, toxicity, systems analysis, and policy analysis. Current methanol-based fuel cell research at JPL and emissions characterization studies at Caltech provided a rich data base. Related efforts, such as the Advanced Coal Extraction Systems study, and detailed cost models being developed for photovoltaic and other new

energy systems, ensured a background and structure conducive to a well-rounded overview of the problem.

The emphasis of the California Methanol Assessment has not been placed on generating new basic data, but rather on resolving conflicting information, performing a more detailed market analysis in California submarkets than has been published to date, and synthesizing this information into a California strategy. Some of the questions that needed to be addressed were:

(1) Could methanol become a significant fuel for California (and elsewhere) beginning in the 1980s and 1990s?

(2) When compared to alternatives, which options for the use of methanol should be encouraged for California?

(3) What are the attributes of methanol in terms of cost, value, environmental impacts, supply reliability, safety, and health?

(4) What are the possible and probable sources of supply and modes of transportation and distribution?

(5) What are viable near-term approaches for the use of methanol as a fuel in California?

APPROACH

The goals of this research effort have been to:

(1) Synthesize, evaluate, and document key technical issues (e.g., neat methanol engine efficiency, economies of scale in methanol production, environmental effects of methanol use, etc.).

(2) Identify the essential features of a mature methanol fuel industry if it should develop.

(3) Identify and characterize potential near-term and long-term methanol fuel markets.

(4) Characterize the next steps in terms of research or studies that would further refine the potential role for methanol.

(5) Determine if selected policy alternatives can significantly alter methanol potential.

After evaluating these key issues, a determination was made of the next steps to be taken in the methanol market. These steps were then evaluated from the perspective of each of the key participants (producers, users, equipment manufacturers, distributors, regulators, legislators, etc.).

Thus, the end result of this study has been to determine if there are useful transition-period strategies, policies, research activities, regulatory changes, or avenues of cooperation among the participants in the methanol

market that would facilite methanol achieving its longer-term role more efficiently. This is a very difficult problem and challenges fuel producers and distributors, automobile manufacturers, end users, government agencies, and researchers to determine sensible processes and policies within a timeframe that will allow methanol to be efficiently available for future demands.

The choice was made of the specific time periods used for near-term (1982 through 1987), transition-period (1988 to 1997), and long-term (1997 and beyond) market analyses because of constraints on the evolution of methanol as a fuel, i.e.:

(1) The near-term period of 5 years is short enough so that changes in methanol production capacity can be estimated with reasonable accuracy (plants are already in planning or construction stages) and the state-of-utilization technology is relatively fixed.

(2) The transition period from 1988 to 1997 is the timeframe in which methanol use would have to expand rapidly if it were to make a significant impact on fuel markets by the turn of the century.

(3) The long-term market is simply defined as beyond 1997 because that is a period by which some results would have to be realized to motivate action now in planning, technology development, and policy implementation.

An effort of this study has been made to examine the possible transition paths of methanol into long-term fuel and stationary source markets. Therefore, this study looks more deeply than other recent studies at the submarkets in transportation, utilities, and industry that could be important in building the supply, production, and delivery infrastructure necessary for widespread use of methanol. For example, in the transportation fuel market potential demand for methanol as an octane enhancer in Califonia is examined as a complex market in itself. The perspective of large refiners and the independents in terms of the value each would place on methanol for octane enhancement is quite different. Similarly, in the case of utilities, an attempt has been made to carefully differentiate the value of methanol in various types of generating units and under a number of environmental conditions and regulations. The results, when aggregated across the market sectors, provide the framework for identifying opportunities for structuring a transition strategy. It is not suggested, however, that this study substitutes for the project-specific analysis a company would have to do to commit to a methanol venture. The level of detail necessary for such an evaluation is simply beyond the scope of this study.

The study has also taken a fairly detailed look at the methanol production industry in the near term (1982 to 1987), as this period may also be crucial to a transition strategy. This period is significant because methanol production is already in a period of transition. The deregulation of natural gas that is now in progress will greatly alter the structure of methanol supply in the long term and may lead to significant price changes in the near term.

Individuals that contributed to this study represented a broad spectrum of disciplines, including chemical engineering, economics, petroleum engineering, policy analysis, and thermodynamics. The sponsors of the study also provided substantial data in the following areas:

(1) Production: Atlantic Richfield Co., Chevron USA, Inc., Conoco Coal Development Co., Exxon Research & Development Co., Phillips Petroleum Co., Sun Co., and Texaco, Inc.

(2) Chemical: du Pont de Nemours and Co.

(3) Utility: Electric Power Research Institute, Pacific Gas and Electric Co., Southern California Edison Co.

(4) Automotive technnology: Ford Motor Co., General Motors Corp.

(5) National synfuel incentives: Synthetic Fuels Corp. (SFC).

(6) State roles: California Energy Commission (CEC).

(7) Production equipment: Litton Energy Systems.

The findings were synthesized into an assessment framework and reviewed by JPL and by the Technical Advisory Group, which is composed of representatives of the sponsors. A key feature of the assessment approach was that the information was exchanged and discussed by the Technical Advisory Group in the same meetings that were held to review drafts of the interim and final reports. Although agreement was not reached on all points, these meetings provided an opportunity to discuss specific issues from the perspective of companies that are or might be potentially involved in methanol production, distribution, and use. Thus, although the study does not represent a consensus position of the sponsors (the conclusions are solely those of JPL), there was a free exchange of ideas so that a wide range of positions could be considered. The reader is referred to Appendix B in Volume II: Technical Report for the positions of the various sponsors on the findings.

FINDINGS

Competitive Environment

A review was made of studies of the present and projected competitive environment for methanol in Califonia with emphasis on: (1) the availabililty and price of natural gas and residual oil to California utilities, and (2) the likely range of cost for motor fuels in California. Table 1 projects the likely (base case) fuel consumption and cost for California for the utility and transportation sectors. The precise values of the forecast prices and quantities are not as important as the general climate for synthetic fuels in the transition period of 1982 through 2000. The key factors during this period are:

(1) The United States and California will remain dependent upon imported oil, although recent off-shore oil discoveries will improve California's position.

Table 1. Base Case Fuel Forecast Summary for California (quad/year)

	1980	1985	1990	1995	2000
VEHICLES					
Gasoline	1.44	1.23	1.10	1.08	1.05
Distillate	0.25	0.30	0.35	0.37	0.40
SUBTOTAL	1.69	1.53	1.45	1.47	1.45
ELECTRIC UTILITIES					
Natural Gas	0.52	0.59	0.54	0.49	0.45
Oil	0.48	0.36	0.49	0.37	0.13
SUBTOTAL	1.00	0.95	1.03	0.86	0.58
INDUSTRY					
Natural Gas	0.54	0.36	0.39	0.39	0.37
Distillate Oil	0.05	0.05	0.04	0.04	0.03
Residual Oil	0.04	0.04	0.03	0.03	0.03
SUBTOTAL	0.63	0.45	0.46	0.46	0.43
PRICES (1981 $/10^6 Btu)					
Gasoline	10.66	9.85	12.42	14.39	15.97
Residual Oil (0.5% sulfur)	5.47	5.49	6.68	7.58	8.18
Distillate Oil	6.30	6.12	7.89	9.37	10.60
Natural Gas: Utilities	3.84	5.01	6.37	7.44	8.06
Natural Gas: Industrial	3.97	5.07	6.41	7.47	8.09

(2) Natural gas after deregulation will tend toward parity with the price of residual oil.

(3) The contribution of synthetic fuels nationally will probably be less than 500,000 barrels (bbl)/day by the year 2000.

(4) Although there is significant oil worldwide and unused capacity in OPEC to supply anticipated demands in the next 20 years at real escalation rates of 2% annually or less, political disruptions could drive prices up much faster.

(5) There is a plausible wide range of oil price scenarios in the 1990s, which work against those large-scale capital projects that must rely on high-price scenarios for viability.

(6) The real price decrease, since the peak 1981 oil price level, has severely impacted the enthusiasm for synthetic fuels and will probably negatively impact such projects even if another sudden price rise occurs.

Air Quality

A special effort of the study that coincided with ongoing research at Caltech was to perform a screening analysis of the likely impact of methanol fuel on the air quality of the South Coast Air Basin. The Basin includes the areas within the counties of Los Angeles, Orange, Riverside, and San Bernardino, which has a population of about 11 million people. The Basin has persistent and severe problems of air pollution caused by a combination of factors. There has been an extensive gathering of emissions and meterological data for this Basin, which enabled the application of analytical models.

For this analysis, an existing Caltech air-quality model was further adapted to treat methanol as a specific pollutant. The methanol chemistry was included in the model for completeness to determine how methanol would contribute to the formation of ozone. Thus, the model was able to distinguish seven classes of reactive organic compounds: alkanes, ethylene, other olefins, formaldehyde, other aldehydes, aromatics, and methanol. The various reactive hydrocarbons have different rates of reaction with NO_x and with the oxygenated species that promote the formation of photochemical smog. The model uses a Langrangian form for representation of the equations of motion that describe the diffusion and convection of chemical species within the modeling region. It calculates the concentrations of chemical species along a given trajectory of an air parcel traversing the Basin.

All calculations were based on the projected emissions inventory of pollutants for the year 2000. The air-quality impacts of methanol use are quite sensitive to this initial baseline, thus the findings discussed below should not be attributed to the intervening years between now and the year 2000. At that future date, the potential benefits of existing pollution-abatement regulations would have been realized. At the same time, it is a feasible date by which, if methanol were to become an important fuel in California, air-quality effects from this change would be felt. Calculations were performed to indicate the likely effect on air quality of using methanol as a substitute for gasoline; no estimates were made of the effects of use of methanol for stationary applications or diesel vehicles because other study findings indicated these uses to be relatively small contributors to the emissions baseline.

Some of the following conclusions apply to the complete substitution of methanol for gasoline in the South Coast Air Basin, based on projected emissions for the year 2000. Even though this is not a feasible scenario for methanol use, the intent was to bound the air-quality implications of substituting methanol for gasoline and to calculate a limiting case. Therefore:

- Even with an optimistic rate of neat methanol vehicle adoption, the maximum impact by the year 2000 would be only a 3% to 4% reduction in the peak hourly-average concentration of ozone.

- In the long term (beyond the year 2000), even the complete substitution of methanol-fueled vehicles for gasoline-fueled vehicles could lead to a reduction of 14% to 20% in the peak hourly-average concentration of ozone.

- Peak ozone concentration decreases approximately linearly with methanol substitution, starting with the year 2000 emissions inventory.

- The photochemical reactivity of methanol is relatively low.

- With use of methanol, peak ozone concentration is reduced as emissions of NO_x are reduced. The ozone concentration, however, is much less sensitive to emissions of NO_x than to reactive organic emissions.

- With methanol substitution, the ambient concentration of formaldehyde would not increase significantly.

- Total suspended particulates in general would not be greatly affected by methanol substitution; however, fine non-volatile carbonaceous particulates would be reduced slightly if methanol were substituted for gasoline. Methanol substitution for diesel fuel would make this reduction much larger.

While the assessment of effects of methanol on air quality is only an initial investigation and while the accuracy of the data used in the modeling calculations could possibly be improved, the study results clearly indicate that the impact of methanol of the South Coast Air Basin would be beneficial in the long term. For some pollutants, the potential improvements are significant. The most significant impact would be to reduce the peak level of ozone, but only if a major portion of vehicles in use were methanol-fueled. Even a small reduction in peak level would cause a reduction in the number of days that the smog episodes occur, and thereby would cause an improvement in the air quality for the residents of the Basin. Obviously, the use of methanol is no panacea for the problems of air pollution. Other pollution-abatement measures would still be needed. If neat methanol-fueled passenger cars were to become over-the-road competitive with gasoline vehicles in 1990, and from that point achieve a rate of sales consistent with the rate of adoption for deisel-fueled vehicles since 1978, the vehicle stock would be about 12% neat methanol-fueled vehicles by the year 2000. With this percentage of methanol-fueled vehicles on the road, the peak ozone would be reduced about 3.7% from the base case. Obviously, the adoption of methanol vehicles could occur more quickly, but this is unlikely given that neat methanol will not be over-the-road competi- tive for some time. Neat methanol has more barriers to overcome than diesel, so its rate of adoption will tend to be less, if anything, than the diesel experience since 1978. Therefore, the 3.7% impact on ozone by the year 2000 for neat methanol-fueled vehicles is probably optimistic and, in any case, only a modest factor in that timeframe.

PROJECTIONS

One of the goals of the study was to characterize the projected value of methanol in the private marketplace. Such a determination will reveal whether there are potentially viable markets for methanol in the near to mid term that might help transition to widespread use of methanol as a transportation fuel.

Near Term (1982 through 1987)

The methanol supply industry is already in a transition period. Adding to the progressing deregulation of natural gas and a worldwide oversupply of methanol, there is a prospect for coal-based methanol plants supported by SFC. Also, there is much uncertainty surrounding the near-term structure of the industry.

Factors acting upon the methanol industry in the near term will be:

(1) By 1985, natural gas will be deregulated and will move toward parity with the mid to low sulfur (approximately 0.5%) residual oil price. In the study's baseline scenario, this is expected to be in the \$4.75 to \$5.00 per 1 millon (10^6) Btu range in 1987 (1981 \$).

(2) Contracts for inexpensive natural gas, currently supplying the conventional feedstock for methanol in the United States, will virtually all have expired by 1985 to 1986. As a result, domestic producers will be paying deregulated market prices for feedstock natural gas.

(3) There will be excess capacity in methanol production to supply traditional chemical markets. Even if demands in traditional uses such as formaldehyde return to pre-recession levels (if the housing industry expands), the 1985 excess supply capacity will probably exceed 1 billion (10^9) gal/year in free-world markets unless fuel uses expand.

Production

Given the above factors that are operating within the industry, three possible marginal commercial production sources by 1987 are: (1) methanol from conventional natural-gas plants with unregulated gas feedstock cost, (2) new remote natural-gas-based plants, or (3) SFC-supported coal-to-methanol plants.

Virtually all of the existing plants will be operating on deregulated natural gas by 1987. Assuming a \$5.50/10^6 Btu feedstock cost for natural gas in fully amortized plants, the plant gate market price for methanol is estimated at a minimum of \$0.76/gal for methanol in 1987 (in 1981 \$). It is expected that these plants will remain viable at least through 1990, but that no new conventional plants will be built based on pipeline natural gas.

The concept of barge-mounted plants producing 2000 to 3000 tons/day from remote natural gas may become viable in this period. The key assumption here is that the remote natural gas used would be available at far-below-market gas prices. Two plant locations were evaluated for feedstock and transport costs appropriate for methanol: Cook Inlet (Alaska) and Indonesia. The implications of these cost projections are that barge-mounted plants could yield a 20% after-tax nominal return with a minimum acceptable delivered price of \$0.58 to \$0.66/gal (in 1981 \$).

Coal-based methanol plants supported by price or loan guarantees have been proposed to SFC. The study modeled a western-sited coal-to-methanol plant and unit train transportation to the West Coast. It was found to require a price of $0.82/gal delivered to California, even with loan guarantees. Thus, even with SFC support, western coal-to-methanol production will not be competitive with the other options, and it seems likely that any coal-to-methanol plants started in the 1980s will have to be subsidized with price supports. Further, subsidized methanol might tend to displace domestic production in the chemical sector, rather than in the fuels market as intended.

Use

Although methanol can be used in utilities and in industry as a boiler or peaking fuel, it must compete with conventional fuels. In the 1987 timeframe, residual oil and natural gas are expected to cost approximately $\$5.50/10^6$ Btu, and methanol should cost approximately $\$9.00/10^6$ Btu. Thus, the only potential for methanol use in the utility/industry sector would be where environmental constraints force a willingness to pay a significant premium ($3.00 to $\$4.00/10^6$ Btu) for methanol. One utility application that seems to have some promise to justify premiums in this range is overfiring boilers using 10% methanol with natural gas or residual oil. Full-scale boiler tests must be done to confirm if such premiums can be justified in selected power plants where capacity is restricted because of emissions limitations.

As in utility and industry applications, there are significant near-term barriers to the expansion of refining and blending submarkets on the West Coast because of lack of availablility of other necessary blending agents such as isobutylene for methyl tertiary butyl ether (MTBE) and tertiary butyl alcohol (TBA) for low-level blends. It is expected that methanol demand for blending and refining will be only 300 to 500 tons/day in the near term because of these constraints.

There now exists a very small methanol market for commercial fleet vehicles, supported by several small companies performing vehicle conversions to neat methanol. Even if factory-optimized methanol vehicles were available and the price of methanol fuel was such that these vehicles would have an over-the-road cost competitiveness with gasoline, the near-term potential market is probably still limited to 4000 to 10,000 vehicle sales per year in California. This is due to constraining factors such as uncertainty of resale value, ready availability of methanol fuel, and required maximum trip lengths for the vehicles. If methanol vehicles were in fact sold at this volume, it would imply an increase in methanol demand of between about 20 and 75 tons/day. Such a volume is quite small in comparison to a remote natural-gas methanol plant size of 2000 to 3000 tons/day.

As shown in Figure 1, the most likely outcome in the near term is for very limited quantities of methanol being consumed within the state. The maximum competitive market size would be approximately 4000 tons/day, even if all the low-level blend potential of California were exploited. A more likely outcome is that demand will be approximately 1000 tons/day, with perhaps 800 tons/day to blending markets, 100 tons/day to vehicle fleets, and 100 to

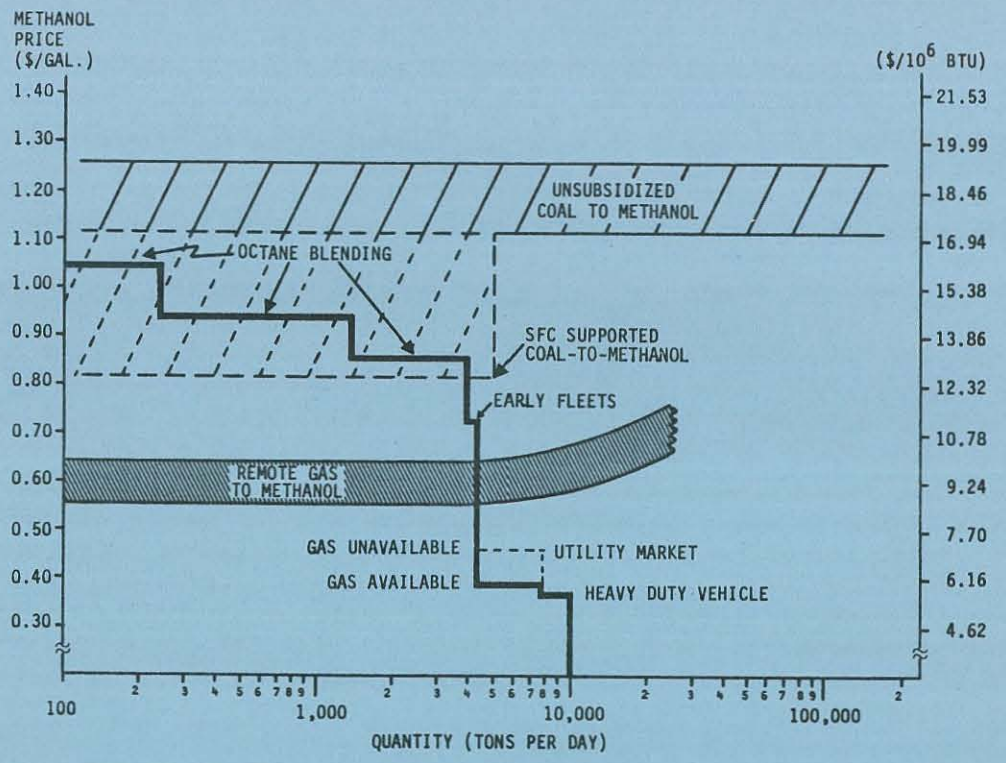


Figure 1. Projected 1987 California Methanol Market (1981 $)

200 tons/day utilized for utility experimentation. The only way that this outcome could be significantly affected would be for: (1) the West Coast TBA capacity to be expanded, (2) the regulatory climate in California to be eased to facilitate the blending with a higher allowed Reid Vapor Pressure, or (3) utility overfiring to be expanded if the potential gains are proven in large-scale tests.

Transition Period (1987 to 1997)

A characterization has been made of the effects of letting the marketplace determine methanol introduction and evolution for the timeframe of 1987 to 1997. The transition period is the most interesting aspect of the evolution of the methanol market because it is a timeframe in which production methods and sources will change, end-use technology will improve, and the fuel market in which it competes may also experience significant changes. The 10-year period from 1987 to 1997 is defined for the purposes of this study as the transition period in which major changes must occur if methanol is to be a significant fuel by the year 2000. Obviously the planning, testing, experimentation, and policy changes might begin sooner, but the impact of these activities on the market will be felt in the 1987 to 1997 timeframe.

Production

There are already capacity additions planned through 1987 based on natural-gas feedstocks that may add as much as 1 billion gallons of excess capacity relative to projected chemical demands. Thus, there is an ample supply of methanol for early utility experiments, fleet use, and octane blending in the next few years. Beyond 1987, the potential exists for additional capacity.

After a detailed comparison of the methanol production costs from both California feedstocks (bioenergy, petroleum coke, heavy oil in rock) and other out-of-state resources (western coal, Alaskan coal and remote natural gas), it has been concluded that only two options would be important to California's transition period: remote natural gas, and SFC-supported coal-to-methanol plants.

A key factor in the conclusion that remote natural gas is the most important source for methanol in the transition period is the expectation that the markets will evolve slowly. Methanol from remote natural gas is not likely to be extremely elastic in supply. At large levels of fuel demand, production costs from this source would begin to rise for two reasons: longer transport distances to California, and higher collection costs in less-developed remote sites.

The major findings in the production cost analysis are that:

(1) Methanol is most efficiently produced from remote natural gas in the transition period.

(2) Production costs from remote natural gas vary from the reference case of $0.53/gal in 1992 up to $0.66/gal at a 25% return and down to $0.42/gal at a 15% return.

(3) The quantities of remote natural gas available on the Pacific Rim at $1.50/$10^6$ Btu or less seem sufficient to support California's near- to mid-term fuel demands.

(4) Rapid expansion of methanol supply from remote gas resources will induce price increases as longer transport and higher collection costs are incurred.

(5) California resources are not critical to a methanol fuel transition.

(6) Methanol does seem to be in the competitive range with shale oil or to be significantly cheaper than methanol-to-gasoline or Fischer-Tropsch liquids.

(7) A high oil price scenario may also tend to induce methanol production cost increases, which offset some of the apparent gains in viability.

(8) There does not appear to be a case in which unsubsidized coal-to-methanol plants become commercial before the year 2000.

Use

Given the starting point illustrated previously in Figure 1 for the bounds on the California fuel market for methanol in 1987, similar snapshots of utility, industrial, blends and neat transport fuel markets are made for 1992 (Figure 2). During the transition period, the most important factor in the status of the methanol fuel market in California will be the competitive environment in which it must compete. The pertinent submarkets are blends, fleets, private passenger cars, industrial fuels, and utility fuels. All of these market potentials are shown in Figure 2 in terms of both breakeven prices and market sizes. Some significant changes from Figure 1 are evident, especially in the scale of the potential stationary applications market and the addition of a light-duty vehicle submarket.

As shown in Figure 2, the transportation markets are the submarkets where methanol can have a limited impact in the transition period. Low-level blends (4.5%) of methanol and a co-solvent with gasoline should be competitive at some level by 1992. The maximum methanol use would be about 3000 tons/day in California for this purpose, but actual use given TBA limitations will

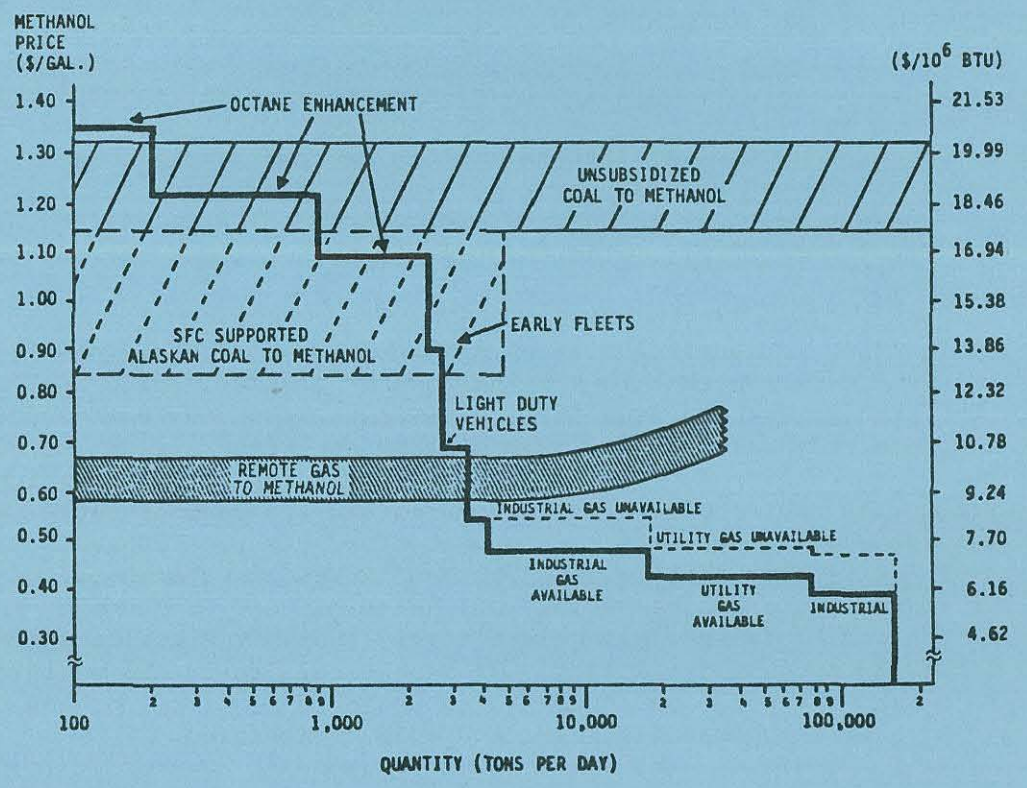


Figure 2. California Methanol Market in 1992 (1981 $)

probably be smaller, about 900 to 1000 tons/day. The fleet market is the next increment in methanol demand that would be competitive at prices up to about $0.90/gal, but would imply a maximum methanol demand of 1200 tons/day and a more likely demand of approximately 100 tons/day.

The passenger car market would also achieve parity in the early 1990s with the over-the-road costs of gasoline, although the margin would be slight. A key factor in this analysis is that only remote natural-gas feedstocks yield methanol prices in the competitive range of fleets and passenger car markets. Because this feedstock source is not highly elastic, a very rapid penetration rate for methanol-fueled vehicles would lead to methanol production-cost increases. At rates of penetration consistent with diesel vehicles in the period of 1978 to 1982, remote natural gas is sufficient to supply both fleets and passenger cars through the 1987 to 1997 period.

Rapidly rising oil prices consistent with the high oil price scenario may improve methanol viability somewhat, but there will also be feedbacks in methanol production costs that offset part of the apparent gain in competitiveness. As a result, with either the base case or high-price scenario, methanol from coal does not seem viable through the transition period. In the low oil price scenario, light-duty vehicles do not become over-the-road competitive until beyond the year 2000, even for methanol from remote natural gas. For this optimistic case scenario, the only viable methanol market is in blending for octane enhancement or possibly overfiring in highly selective utility applications.

The potential for methanol as a fuel in stationary applications is very limited in the transition period because it cannot be produced competitively with pipeline gas or even liquefied natural gas (LNG). This situation is actually strengthened under a high oil-price scenario, where feedback effects in methanol production costs will offset likely increases in pipeline gas. Under the assumption that natural gas remains available to utilities (which seems likely), the margin for error between costs for natural gas and methanol is estimated to be sufficiently wide that methanol cannot compete on strictly an energy basis.

The only other rationale for using methanol for stationary applications in this timeframe would be that it has environmental value beyond its energy content. The problem with environmental premiums is that there are current programs in place that rely primarily on nuclear capacity, out-of-state coal generation, and renewables to achieve environmental compliance. Burning methanol within the South Coast Air Basin is neither as cost-effective as these options nor as environmentally benign with respect to NO_x and sulfur output in the Basin. The one exception to the lack of environmental premiums is the case where plants are operating well below capacity because of NO_x output limitations. These few plants are really the only transition-period methanol market in the utility sector. If bench-scale tests are verified in large-scale tests, the value of methanol may exceed that of oil or gas by more than $\$3.00/10^6$ Btu, which would make it a viable application.

Long Term (1997 and beyond)

Production

In the period beyond 1997, if the preconditions on methanol development have been successfully achieved, there are really only two potential feedstock sources for methanol: western coal and Alaskan North Slope natural gas. Both of these feedstocks exist in sufficient quantities to supply an established and growing methanol fuel demand, and have further strategic value as domestic sources which are not subject to Middle Eastern political and social instability. For natural gas the supply elasticity is such that quantities of 10,000 to 20,000 tons/day can probably be supplied before large supply cost increases take place. These cost increases result from increasingly higher feedstock acquisition and collection costs, and also from costs associated with longer product transport times. As a result, these costs would increase until the potential for North Slope gas could be exploited (about 10,000 tons/day). Of course, if the gas pipeline to the North Slope is constructed, methanol will cease to be a relevant option. For coal-to-methanol plants, larger quantities might lower production costs for a period while production and transport economies are exploited. The minimum acceptable selling price for coal-to-methanol production, shown in Figure 3, is expressed

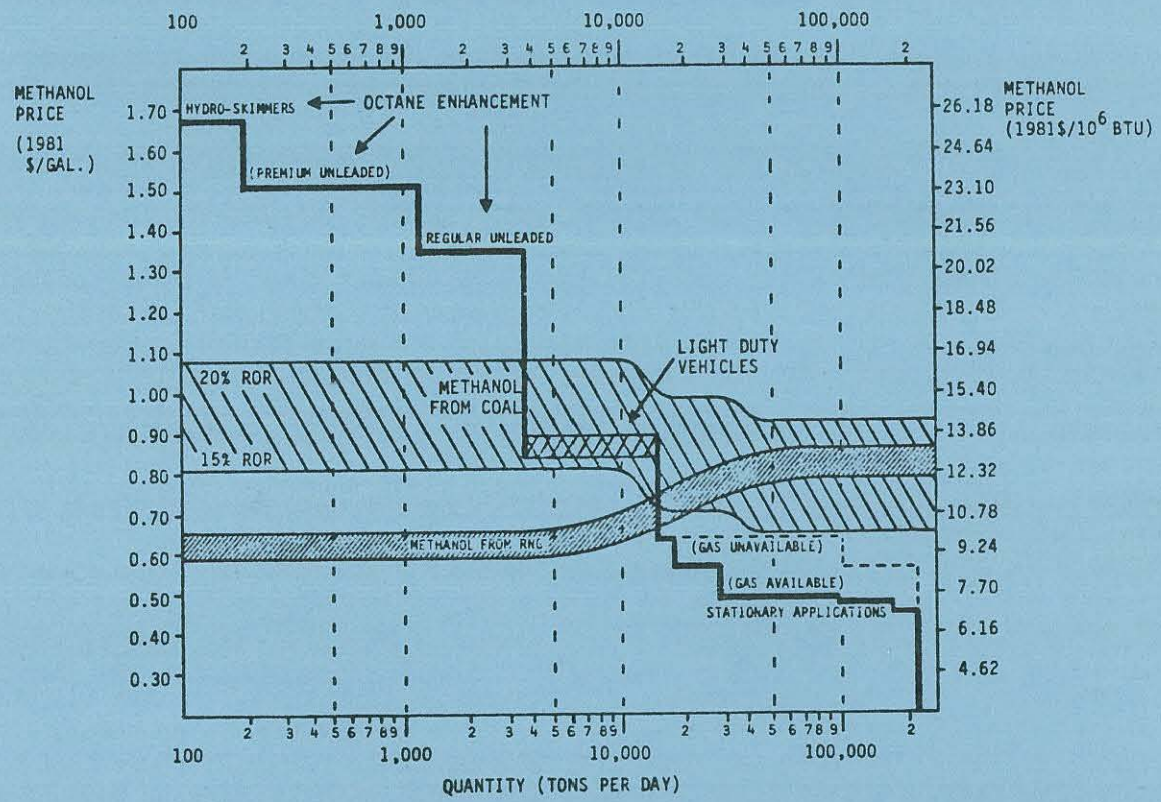


Figure 3. Methanol Fuel Markets Beyond the Year 2000 (1981 $)

as a range reflecting uncertainty about the potential economies of scale, required rates of return, and transport options. Even under the most optimistic assumptions, coal-based methanol would not be competitive in stationary applications, while in the baseline case (20% return, modest economies of scale and pipeline transport), methanol would not be competitive with gasoline until beyond the year 2000. Thus, it is not anticipated that unsubsidized coal-to-methanol plants in the United States will be initiated in this century.

Use

The dominant long-term market for methanol as a fuel, as shown in Figure 3, is in light-duty passenger vehicles. That is not to say that there will not be other important markets, but they will be much smaller in size; in this smaller but important category, methanol may be used in utilities in the period beyond the year 2000 for limited peaking requirements, and by industry and utilities as a boiler fuel in environmentally sensitive areas.

The highest value submarkets are for octane blending, but these markets are very small, totaling to no more than 2000 tons/day. Light-duty vehicles should be the next highest value market which is also small initially. Figure 3 also shows that the prospects for methanol use in stationary applications are not very optimistic in the case where natural gas is available. In fact, as strictly an energy source, methanol is not likely to compete with LNG or medium Btu gas (MBG) as a fuel source for combined-cycle plants or for repowering oil-fired boilers. There may be a small utility role for methanol in dual-fueling plants under strict control for NO_x emissions.

PUBLIC AND PRIVATE SECTOR ROLES

From California's perspective, there are two overriding motivations for examining methanol as an alternative fuel in stationary and transportation applications: security of supply and environmental improvement. However, both of these factors may not be sufficient to induce methanol implementation if their value is not sufficient to make methanol viable in specific applications. An examination was made based on the available data to see if there is justification for government intervention in the private marketplace to either facilitate or accelerate methanol production and use, given the projection of what the consequences would be of letting the market determine methanol introduction and evolution. Thus, the goal here was to determine from the data developed in the study and other sources whether a government role is justified and, if so, what the impact of government policy would be on the methanol fuel market.

The first step in determining the appropriate policies for the public sector in the evolution of methanol as a fuel in California is to examine to what degree the private market is not providing proper incentives for methanol use. Rationales for justifying a public role were examined for an oil import premium and an environmental premium based on lower emissions. Although quantitative estimates on these types of premiums are admittedly imprecise,

they do provide some rough guidelines on whether the social benefits of methanol are sufficient to justify its cost.

In areas where there was simply too much uncertainty to formulate a policy for methanol use in the state, the objective is to evaluate whether the preconditions exist in terms of efficient markets and other institutional mechanisms for the expansion of methanol-fuel use if it meets the market test. Emphasis was placed on examining mechanisms that help the market reflect the cost and benefits of methanol as they become known and that efficiently transmit them to both potential producers and consumers.

The rapid changes in events and trends in the last decade are an indication that our understanding is quite limited of how energy markets in general and international oil markets in particular will evolve. During the last 8 years since 1974, the forecasts of energy demand have changed dramatically in response to a better understanding of supply and demand elasticities, Middle East politics, and the evolving policy of the United States.

Oil Import Premium Policy

Implementing an oil import premium policy, such as a tariff on oil imports, is more efficient than subsidizing a specific option (like methanol or shale oil) in that it does not bias the selection process. Based on a recent study* which placed a bound on the likely value of a United States import premium from $8.00/bbl to $20.00/bbl, Table 2 shows the impact of the premiums on the baseline cost of gasoline. The implication is that if methanol were competitive with gasoline at $1.74 in 1990, there would be reason to believe that a national policy of imposing an import premium (for instance through a tariff) would induce a methanol market. If methanol required a gasoline price of more than $2.03/gal in 1990 (in 1981 $) to be competitive, then even a premium would not induce a methanol market. The study analysis indicates that an increase in gasoline prices of $0.19/gal (in 1981 $) does significantly accelerate the period at which methanol becomes a viable transport fuel (by about 4 years) for methanol made from remote natural

Table 2. Gasoline Prices With the United States Import Premium

Year	Baseline Gasoline Market Price, $	Gasoline with Import Premium	
		$8/bbl	$20/bbl
1990	1.55	1.74	2.03
1995	1.80	1.99	2.28

*World Oil, Energy Modeling Forum, Institute for Energy Studies, Stanford University, EMG Report 6, February 1982.

gas. For methanol from coal, the breakeven timeframe is so far in the future that an import premium would not have a significant impact.

The conclusions of this study on the issue of national security are that: (1) if there is a value ($8/bbl) above the free-market oil price to oil import reduction in the United States, there would be little impact on coal-based methanol; (2) any attempt to implement such a policy should be done at the national level, where the costs are spread among all beneficiaries; (3) an oil-import premium should be implemented in a neutral manner (e.g., oil-import tariff) to allow the market to select the best alternatives; (4) an import premium of $8/bbl would raise the retail price of gasoline about $0.19/gal, which would accelerate the over-the-road competitiveness of methanol and other synfuels 4 to 5 years if the premium were believed to be of a stable duration; (5) from a fuel security viewpoint, methanol is not significantly different from other synfuels that substitute for imported oil; and (6) within California, the value which can be justified for a California-only oil import premium is smaller because the market power component (impact of substitution on lowering the world oil price) is reduced considerably compared to the nation as a whole, as most of the benefits would accrue to others.

Environmental Policies

Another nationwide concern with special significance for California is the air-quality problem in its urban centers. In this regard, methanol does have unique properties compared to other transportation synfuels such as shale oil, Fischer-Tropsch liquids, and products of direct coal liquefaction, as well as conventional gasoline and diesel fuel. It is also clear that substitution of methanol for oil in utility applications can lead to some benefits as a result of reductions in NO_x, SO_x, and particulate emissions. The value of these benefits to the utilities, however, is not as clear.

Utilities in the South Coast Air Basin (Los Angeles and vicinity) and in the Ventura Country Air Pollution Control District (especially Southern California Edison and Los Angeles Department of Water & Power) are required to reduce their NO_x emissions by 60% by the year 1990. Use of methanol in some units could be included as part of an overall strategy to satisfy this requirement. This could lead to payment of a premium for methanol. A similar requirement is under consideration to limit SO_x emissions in the South Coast Air Basin, and there may be requirements to reduce particulate emissions.

The premiums for the values for methanol as a pollution abatement strategy would be an additive for NO_x and SO_x. Thus, the potential premium value is approximately $0.65 to $0.90/$10^6$ Btu, or about $0.05/gal of methanol. This size premium is not likely to induce use of methanol in many plants. The cost difference that has been calculated between methanol and conventional utility fuels is much larger than this value. Nevertheless, in the longer term it would be highly desirable if a market system were established to create a stable mechanism for determining the value of the premium that methanol or other clean fuels should have as part of an efficient environmental program. Based on the data that exist to date, however, implementation of a policy to internalize these environmental attributes of methanol would not significantly accelerate methanol use.

Subsidies

As far as the State of California is concerned, there is little to be gained from subsidizing production of methanol because the Federal Government has already assumed that role. Eventually it may be in California's interest to have a western coal-to-methanol project among those awarded assistance by SFC. The State can improve the likelihood of this type of project by helping prospective project sponsors and supplying data on California markets for methanol. There does not seem to be a justification, however, for any state-sponsored production subsidy to either augment or duplicate SFC's program.

The one area where the State, through its Public Utility Commission (PUC), can make a contribution to lowering the cost of methanol production is in further development and the eventual demonstration of the once-through methanol, coal-gasification, combined-cycle concept. Potential efficiency gains in the once-through process imply that a cost saving of about 20% (aside from utility financing impacts) may be possible from such a system when compared with a dedicated methanol plant. Proposed experimental programs by California utilities for development of this process should be given careful consideration by PUC.

Near-Term Programs

To improve the acceptance of methanol as a fuel, the State of California might implement the removal of institutional barriers arising from regulations and restrictions not conceived with methanol in mind. The California Energy Commission (CEC) has been active in searching for such unintended barriers and has been successful in eliminating the most important obstacles. For example, the state gasoline tax will be levied on methanol on a Btu basis equivalent to gasoline rather than on a gallon basis. Taxing methanol on a gallon basis would have penalized methanol relative to gasoline. The State has also sponsored tax credits for converting vehicles to neat-methanol use, which have been responsible for initiating fleet conversions within California. In general, CEC has been diligent in encouraging alcohol-fuel use through barrier elimination, developing test information through its alcohol fleet test program, and providing incentives for vehicle conversion.

The focal point of the State's plan currently is the $5 million program to purchase and support approximately 1000 fleet vehicles, to establish 50 to 100 commercial refueling stations in California, and to test methanol-fueled California Highway Patrol pursuit vehicles. These activities are intended to help develop market stimulus, which will eventually lead to a self-sustaining methanol fuel market. Related efforts are also under way to demonstrate methanol in heavy-duty diesel engines and in stationary applications (repowering and co-firing). These other programs for different types of applications are important to CEC's strategy of developing methanol uses that displace the majority of refined products from crude oil. The Commissions's rationale for this strategy is that an alternative fuel that only displaces gasoline, for example, could have adverse effects on the existing petroleum product slate, necessitating refinery modifications and/or relative price changes in refined products. The stated goal of these programs is to accelerate the "take-off" point for self-sustained commercial market growth.

Given the abrupt reduction in the expectation for conventional fuel prices that has occurred in the past 2 years, and the significant rise in projected cost of synfuels, it is important to assess what government programs can realistically accomplish in this environment. First, it is clear that the viability of synthetic-fuel projects has deteriorated significantly in this 2-year period, as evidenced by the cancellation or postponement of numerous synfuel projects. Second, the excess capacity in OPEC oil production makes a near-term oil disruption less likely than it was a few years ago. The net effect of these factors is that the market viability of the long-term neat methanol-fueled vehicle market supplied by western coal has been pushed back until after the year 2000 in the most likely scenarios. The major fuel producers have little incentive, in the view of this study, to move aggressively toward creating the supply and distribution network needed for the use of neat methanol as a large-scale transportation fuel in the foreseeable future. There are, however, other selected markets where methanol will be used successfully during this period: octane enhancement, some captive fleets, and limited use by utilities. Programs that are oriented toward these limited goals can be successful in the period before 1990, but not if they are expected to lead to a private passenger car market.

In stationary applications, the potential market with the greatest promise for being economically viable is overfiring with a small percentage (10% to 15%) of methanol. This concept, if successful, can lead to a justifiable premium for methanol sufficient to overcome its added cost if the capacity factors of plants constrained by NO_x emission restrictions are expanded. In effect, the value of this additional operational capacity added to the value of methanol fuel can be substantial, but it is limited to those plants that are NO_x-constrained. This study strongly supports the conducting of tests to confirm the potential performance of methanol in the overfiring mode. To be of greatest value, however, it is important for overfiring with methanol to be tested against overfiring with natural gas. A significant proportion of the benefits of overfiring may be achievable at lower cost with natural gas overfiring, which would reduce the justifiable premium for methanol. This submarket of utility operations is relatively small (1750 tons/day of methanol) compared to utility fuel use, but quite significant relative to current use of methanol as a fuel. Thus, although a major use of methanol is not anticipated as a fuel substitute for residual oil or natural gas in utilities, it may be benefically used in highly selective applications (e.g., overfiring in environmentally restricted plants).

One possible method for achieving greater use of methanol within California is for government policy to be used to promote (perhaps even require) utility applications as a means to provide a base for expanding fuel use into transportation markets. For a number of reasons, it is believed that this policy would not be a desirable means to transition to large-scale use of methanol as a transportation fuel. First, the value of methanol in transportation markets (especially octane enhancement) is considerably higher (i.e., at least double) than its value as a utility fuel. As a result, methanol will be used first in these higher value markets and will be applied only to lower value uses as the methanol competition increases production and lowers price. Second, the cost of producing methanol in large quantities will be too high to compete with conventional utility fuels. Thus, utility customers would have to pay a large premium ($\$3/10^6$ Btu for methanol from remote natural gas)

over current utility fuels, which cannot be justified by any realistic assessment of the benefits. Third, the experience gained in transporting, handling, purchasing, storing, and using methanol would be based on utility use, which would not carry over to transportation fuel companies. Fourth, although the quantities of fuels used by utilities are sufficiently large to utilize the output of a coal-to-methanol plant (once thought to lower cost through volume production), the cost of methanol would be considerably higher than from much smaller plants based on remote natural gas. Thus, the strategy of inducing utilities to use methanol through public policy as a means of transition to more widespread use in other applications is not attractive. This conclusion is not intended to imply that public support of programs is inappropriate to test methanol use in potentially viable utility applications, but rather that these programs should be justified based on their own merits as to their ability to benefit utilities and their customers.

One often discussed obstacle in implementing widespread use of methanol in transportation is that the retail distribution system must expand rapidly in anticipation of automobile manufacturers producing and selling neat methanol-fueled vehicles to the general public. The problem with distributing methanol is that part of the existing gasoline distribution system (seals, hoses, patches in tanks, etc.) would not be compatible with methanol use. Compounding the problem is the fact that the most recent cycle of replacements at retail outlets has been done with fiberglass tanks instead of steel, which makes the existing system even less compatible with methanol. Creating a parallel system for methanol by replacing functional equipment now used for gasoline presents a significant cost and hence an obstacle to methanol. The lead time that exists, however, before methanol can compete as a private passenger car fuel provides time to create a threshold distribution system much more efficiently. Currently in California there are approximately 18,000 retail gasoline stations supplying transportation fuels to the public. As a general rule, the tanks and pipes in these stations have an expected life of 20 years, which, with a uniform replacement rate, would imply about 900 replacements per year. Even a single company therefore could create a threshold distribution system in a short lead time. For example, if 20% of the regularly scheduled replacements (tanks, pipes, pumps) were made for methanol-compatible systems each year, that would imply approximately 150 to 180 conversions per year. Thus, if this program were started in 1990, by 1996 about 1000 systems would be in place that could be used to distribute methanol. Some cleaning of the system would have to be done when the conversion actually took place, but that would not impose a major cost. The cost of methanol-compatible systems versus conventional systems installed without this program is a crucial factor in its usefulness. The cost for replacing a tank, piping, and two pumps at a typical service station is approximately $50,000 (in 1981 $) for a fiberglass system, and somewhat less expensive for a steel system. The latter, although less expensive, has a lifetime that can be considerably smaller, depending on the climatic conditions to which it is exposed. In addition to the costs of more frequent replacements with a steel system, there are additional costs arising from station disruption and the risk of damage caused by undetected leaks. With the relatively dry climate in much of California, the added cost for methanol-compatible systems should not be great or a major impediment to methanol use. The costs of such a program would seem to be fairly modest when compared with a coal-to-methanol plant. For example, if the extra cost for a methanol-compatible system were $5,000 per installation, then 150 stations per year

would cost $750,000. Although this is not a trivial sum of money, the cost over 6 years is $4.5 million to create a threshold distribution system of 900 retail outlets, which is less than 1% of the cost of a 5000 tons/day coal-to-methanol plant. If instituted in this type of incremental fashion using the normal replacement cycle, the retail distribution barrier need not be a massive obstacle to widespread methanol use. Obviously, the transport system would involve more than the retail distribution outlets, but the delivery system is well within the capability of the private sector if the economic viability of methanol is favorable.

CONCLUSIONS

A successful strategy for making a transition to widespread use of methanol as a fuel must be consistent with the realities of the fuel market in which it must compete. It is clear that in the last year and a half, the climate for introduction of synthetic fuels has changed dramatically. In 1981, oil prices in constant dollars reached a peak from which they have since fallen approximately 20%, but even more important is the change in expectations for the future. It is widely believed that real oil prices will fall in 1983 and then remain constant in real terms through 1985 and only rise to 1981 levels by the end of the decade.

When this study was first conceptualized in 1980, the expectation was that more emphasis could be placed on actual mechanisms to implement large-scale methanol use in the next 10 to 20 years. However, as a result of changes in the oil market as well as more realistic estimates for methanol production costs, elaborate transition strategies are not possible at this time. Methanol is simply too costly for large-scale implementation (e.g., substitution for utility fuels or gasoline as a neat transportation fuel) to be feasible.

These general conclusions, and the more specific ones that follow, represent the best judgment of the study's authors based on the data and analysis incorporated in Volume II: Technical Report. Not every finding can be rigorously proven, because this subject requires some judgment on future behavior of fuel markets, technologies, and government policy, which cannot be known with certainty. Thus, the conclusions are offered as logical interpretations of the existing data.

Supply

- The sources of methanol in the near term will be dominated by natural gas as the feedstock. After deregulation of pipeline gas, no new plants are likely to be built based on this resource, although it is anticipated that most existing plants will continue to operate for the rest of the 1980s and early 1990s.

- New plants throughout the world, already under construction or in planning stages using remote natural gas, will be sufficient to satisfy modest fuels demands through 1987.

- The projected excess methanol production capacity relative to chemical market demands through 1987 could exceed 1 billion gal/year.

- While large quantities of western coals exist that are potentially available for methanol conversion for use in California (in particular, the subbituminous coals of Black Mesa, San Juan, Yampa, and Powder River), substantial support including price supports and loan guarantees would be required to be viable.

- In the near-term and transition periods, the likely quantities of methanol demanded could not justify a methanol pipeline from western coal fields.

- Where large volumes or distances are required, there is a clear economic advantage of transporting methanol by means of tankers or pipelines when compared with rail or truck.

- Indigenous California resources are either too limited in supply (bioenergy, petroleum coke) or too expensive (heavy oil in rock) to support a major transition to methanol fuel within the State. Small selective markets, however, will probably be served by these in-state resources.

- Existing methanol producers will compete successfully in chemical markets at production costs of $0.67/gal through 1987.

- There is sufficient remote gas to supply California demands for the next 15 years at prices that would undercut any unsubsidized coal-to-methanol project.

- One of the implications of SFC's proposed support of coal-to-methanol plants may be to displace methanol produced by the United States chemical industry.

- Methanol producers should be able to compete for use of some remote natural gas with LNG producers given that methanol has a higher value per Btu in transportation applications than LNG and methanol has a production advantage in smaller gas reserves.

Demand

- The stationary applications market will be small. If the dual-fueling concept can be demonstrated to work effectively and plants currently limited in operation by NO_x regulations can be operated at rated capacity using 10% methanol, the implied premium may be sufficient to make methanol competitive in these plants. The maximum market in this case is only 1500 tons/day, and the dual-fueling technology is yet to be demonstrated at full scale.

- No economic use exists for methanol as a fuel for repowering boilers, even with the credit for eliminating the need for environmental control technology.

- A small market will exist for methanol as a gasoline blending agent by the smaller (topping and hydro-skimming) refineries. This market seems to be presently existent at current methanol prices.

- Blends (low-level) have a maximum market in California of approximately 4000 tons/day of methanol, but it is limited by the availablitiy of tertiary butyl alcohol. Thus, the actual demand will probably be small in the near term.

- Neat methanol-fueled vehicles will experience a slow growth rate because they will not achieve even a slight over-the-road cost advantage (based on remote natural gas-based methanol) until after 1990, although this advantage will increase over time (coal-based methanol would not be competitive until beyond 2000).

- If methanol-fueled vehicle use were to grow as quickly as the diesel market, which is doubtful, the proportion by the year 2000 would be about 12%, which would present a level of demand consistent with remote natural gas-based methanol from the Pacific Rim.

- With likely improvements in conventional gasoline vehicles, projected fuel factors as low as 1.3 for neat methanol-fueled vehicles are unrealistic in the long term. Potential improvement from a 1.7 fuel factor (existing technology) to a 1.6 fuel factor in the long term (advanced technology) is possible.

Strategy

- Methanol availability in the long term can be effectively aided by the State of California by facilitating methanol transport by tanker and pipeline. In the near term, port facilities at Long Beach and San Francisco Bay, and at coastal power plants are sufficient for any anticipated needs. In the long term, pipelines from western coalfields will be crucial links in efficient systems if the methanol demand expands.

- Given proper incentives to act, utilities would need a 4- to 8-year development period for widespread conversion and use. The transportation sector would require a 20-year period. At current prices, however, there is little incentive to begin this process.

- Artificial demand created by regulations to induce greatly increased methanol use (i.e., 50,000 tons/day) will lead to rising methanol supply costs as longer transport and higher remote gas collection costs are incurred, and thus would be self-defeating.

- Attempts to favor the use of in-state feedstocks will only slow the methanol transition by raising methanol production costs.

- Methanol can form part of an effective strategy for the control of photochemical smog and fuel diversification after the year 2000.

- Even in the absence of government intervention, the private sector is fully capable of implementing large-scale use of neat methanol as a transportation fuel when it becomes viable.

- There is no evidence that the "derived likely roles" for methanol resulting from government policy to correct externalities significantly affects the free market rate of methanol use in the period through 1995.

RECOMMENDATIONS

- Technology development should be pursued to improve methanol viability in the long term. Production technologies (e.g., co-production, once-through concepts), utilization technologies (e.g., advanced neat methanol automobile engines, methanol overfiring), and demonstrations (e.g., California fleet program) can contribute to improving the viability of methanol versus conventional fuels.

- Further work may be done to improve the demand analysis of methanol in selective target markets where methanol may command a premium value: performance automobiles, selected fleet operators, specific refiners, etc.

- In the policy area, the most productive activities would be to create better institutions to take into account the environmental value of methanol (e.g., markets for licenses to emit NO_x or SO_x).

- The selective markets that seem viable in the near term (octane enhancements, utility boiler overfiring, selected centrally-fueled fleet operators) should be pursued to gain the experience in handling, maintaining, and operating with methanol fuels.

- Policies that attempt to rapidly expand methanol use through mandates should not be enacted because they would be self-defeating. Relatively inexpensive feedstocks cannot supply a large methanol fuel market, opportunities for technological advance would be lost, and the chance to use the normal replacement cycle for distribution systems could not be taken advantage of if methanol were forced into the fuel market too rapidly.

CHAPTER ONE

INTRODUCTION

The technical support for the conclusions in the Summary Report is embodied in the chapters which follow. These chapters are a result of a critical review of the recent literature on the subject, information supplied by the study sponsors, and our own analysis.

As a means to facilitate covering a very broad subject as efficiently as possible, many of the major parts of the study were done in parallel (e.g., methanol production, utilization in vehicles, utilization in stationary sources, and air quality implications of methanol use). There was a common framework established for each examination, i.e., the emphasis was on covering the status of each technology, the long-run potential, the transition period analysis, and finally the policy options which might influence the transition paths. This techical volume divides each technology into a separate chapter. A different approach is attempted in the summary volume, where many of the sections are organized by timeframe rather than by technology. The intent is to have the summary report be a cross-cutting presentation of our findings. Through this type of organization it is hoped that the reader can focus on the most relevant form of the information for his own purposes.

Within the technical report, we have used Chapter 2 to define most of the different routes or end-to-end systems by which methanol could be brought to alternative end-use markets in California. This chapter serves as both a framework and a synthesis of the alternatives which are pertinent to both the long-run methanol market and the transition analysis.

As the starting element in an end-to-end system, the feedstock alternatives are reviewed in Chapter 3. Relevant sources for feedstock include options within the state (petroleum coke, heavy oil in rock, and biomass), those which could be imported directly (western coal) and those which could be used for conversion at their source (western coal, Alaskan coal or remote natural gas). The scale of these resources, locations of deposits, and resource quality are characterized in this chapter.

For each of the different feedstock classes for methanol production, we have performed a production cost analysis. First, the conversion technologies are briefly discussed to identify the most important characteristics of each. A prototype plant is then specified and costed in a consistent manner. Finally, a product cost analysis is done using a present value type of analysis. A representative set of sensitivities are run to identify how production costs are influenced by such factors as changes in rates of return, plant capacity factor, higher feedstock costs, capital cost overrun and changes in the start-up date. These plant specifications, plant cost estimates, production cost estimates, and sensitivities were made for methanol plants based on coal, natural gas, petroleum cake and bioenergy. Since methanol may be competing not only against conventional oil and gas sources, but also against other synfuels, a cost comparison has been made with unconventional sources such as coal liquefaction, coal gasification, and shale oil.

The next component of an end-to-end system is the transport, storage, and distribution needed to bring the product or feedstock to its end-use market or conversion location, respectively. In Chapter 5, the distribution and transport problems are identified, possible solutions discussed, and the cost of alternative options evaluated. The importance of transport is illustrated by the significant range of transportation-related costs which can be experienced among rail, pipeline, tanker and truck modes. Another aspect of methanol transport and storage is the necessity for keeping water out of the system and the potential difficulty with corrosion in existing tanks and pipelines.

One of the most desirable attributes of methanol is its environmental characteristics. Since all sulfur is removed prior to methanol synthesis, the fuel can be burned sulfur free. In addition, the NO_x emissions from end-use combustion of methanol are also significantly lower than from oil-based products. A concern has been raised that aldehyde emissions may pose problems which offset some of these benefits. In Chapter 6 the issue of the environmental consequences of widespread methanol use is evaluated, primarily with respect to its use in vehicles. A model of the Los Angeles Air Basin is used to examine the air quality consequences of different levels of neat methanol vehicle use in the basin, compared to projected emission profiles for the year 2000.

As a means to establish the starting point for the evolution of the methanol fuel market, a brief description of the chemical market is given in Chapter 7. The current sources and uses of chemical methanol are identified and a projection obtained from other sources is included. Of particular interest in the transition period to fuel methanol is the expanding methanol production capacity throughout the world. These new sources are identified together with their expected impact on the demand/supply balance.

One of the most significant motivations for examining synfuels is to develop an alternative transportation fuel to conventional petroleum. Uses of methanol in alternative transportation markets are examined in Chapter 8. One potential market is as a blending agent for octane enhancement or in higher level blends as a volume expander. Another possible market is for neat methanol use in vehicles, where a particularly important issue is how efficient neat methanol-fueled vehicles will be in terms of the fuel factor required compared to gasoline-fueled vehicles. Two possible transition markets for neat methanol vehicles, medium- and heavy-duty vehicles and light-duty fleets, are also examined. In each of the above submarkets dealing with vehicles, a review is conducted of the technical issues, the economics involved in the application are assessed, transition path constraints are identified, and finally, policy options which might alter the transition path are examined.

Another area where large-scale fuel use occurs in California is in electric utilities and industrial boilers. The potential in California for methanol use in both of these applications is significant for one major reason: environmental concern. Although methanol is not likely to compete with natural gas or residual oil on an energy basis, it has additional value in high pollution areas such as the Los Angeles basin. This additional value may arise from using methanol to achieve NO_x emission standards, thereby

(6) California has unique fuel requirements because of environmental problems that make it a valuable study focus.

The basic framework of the study was constructed by assembling as sponsor organizations, which are either involved now or would be instrumental in a successful methanol market. The intent of this approach has been to work directly with many of the most knowledgeable sources of information on: fuel production (ARCO, Chevron, Conoco, Exxon, Phillips, Sun, and Texaco), chemical methanol (du Pont), utility potential (EPRI, PG&E, SCE), automobile technology (Ford, General Motors), national synfuel incentives (Synthetic Fuel Corporation), state governmental roles (California Energy Commission), and production equipment (Litton), and to synthesize the collective wisdom of this group and subject it to analysis by JPL teams. Thus, the emphasis has not been placed on generating new basic data, but rather on resolving conflicting information, performing more detailed market analysis in California submarkets than has been published to date, and synthesizing this information into a California strategy.

Although many sponsors were involved in supporting this study, providing data, and reviewing its findings, the conclusions are not necessarily agreed upon by each of the sponsors. This document does not represent a consensus view in any respect; in fact, with such a diverse set of sponsors, it is not surprising that there are many divergent viewpoints (see Appendix B of the Technical Report for sponsor comments).

Although the focus of the study is on methanol utilization within California, examination of methanol production, however, was not so constrained, as it would have artificially distorted the results. This broader view was given to policy issues as well, and includes an examination of national policy toward synfuels, but concentrates on options that can be implemented at the state level. Thus, although it is recognized that there is a world market for methanol with inherent supply/demand implications, the study has concentrated on California's particular markets, regulations, air quality problems, and competitive environment.

C. ORGANIZATION

This Summary Report contains eight sections that are drawn from the California Methanol Assessment - Volume II, Technical Report, JPL Publication 83-18, JPL Report 5030-562, March 1983. The technical chapters deal with particular subjects (e.g., feedstocks, methanol production, transport, utilization in vehicles, etc.) throughout the analysis period from 1982 through the year 2000, covering the pertinent aspects of technology, economics, and policy. In this Summary Report, these topic areas are synthesized by timeframe (near-term industry, transition paths, and long-term markets), and cross-cutting topics (policies, environmental implications). The choice of the specific time period used for near-term (1982-1987), transition-period (1988-1997), and long-term (1997-beyond) market analyses was made partly for convenience in organizing the discussion and partly because of real constraints in the evolution of methanol as a fuel. For example, the near-term period of 5 years is short enough so that changes in methanol production capacity can be estimated reasonably accurately (plants are already in planning or construction

CHAPTER TWO

OVERVIEW OF CALIFORNIA METHANOL ENERGY DELIVERY SYSTEMS

A. INTRODUCTION

This chapter provides an overview of California methanol energy delivery systems based on the results of the detailed analysis in the following chapters. This overview is intended to serve as an introduction to the various systems that have been proposed for supplying methanol to California, and for using it as a fuel within the state. The overview also provides an indication of the relative significance of the methanol options in terms of potential supply and demand quantities and price competitiveness with alternative fuels.

The general approach was to set up energy delivery systems consisting of subsystems for resource extraction, conversion to methanol, transportation and distribution, and end-use, and to quantify for each system such key factors as resource supply, end-use demand, the minimum required price of delivered methanol based on production cost and the target price for methanol based on prices of competing fuels. To facilitate comparisons, all resource and fuel quantities are expressed in terms of quads (quadrillions Btu at the higher heating value) or quads per year of delivered methanol (i.e., with conversion efficiency taken into account), and all prices are expressed in 1981 dollars per million Btu ($/10^6 Btu) of methanol.

B. DATA COMPILATION AND ANALYSIS

Preliminary investigations led to the conclusion that, in practically all cases, methanol produced in large quantities from a specific source will not necessarily be targeted for one specific use. Instead, the methanol can be applied to a variety of uses. Thus, rather than focus on individual energy delivery systems that cover all the ground from resource to end use, it was decided to split the systems into those that supply methanol and those that use it. The end point of the first type of system is a set of methanol distribution centers located near California metropolitan areas. This concept is illustrated in Figure 2-1, which identifies the systems covered in this chapter. All logical combinations of subsystems studied to date were included in this analysis. The one exception to the distribution center path is the dispersed production of methanol from biomass for use in dispersed agricultural applications. It should be noted that in the approach illustrated in Figure 2-1, the distribution center may be a dummy node: e.g., methanol could be shipped directly from a production facility in Indonesia to a coastal power plant in California, without passing through a real distribution facility.

Data compilation and analysis for each of the systems identified in Figure 2-1 are discussed in the following subsections. Worksheets used in this process are included as an addendum to this chapter.

The bottom line for the supply worksheets is the minimum required price of methanol in dollars per million Btu delivered to the distribution center in the first year of operation. This was estimated by starting with the feedstock

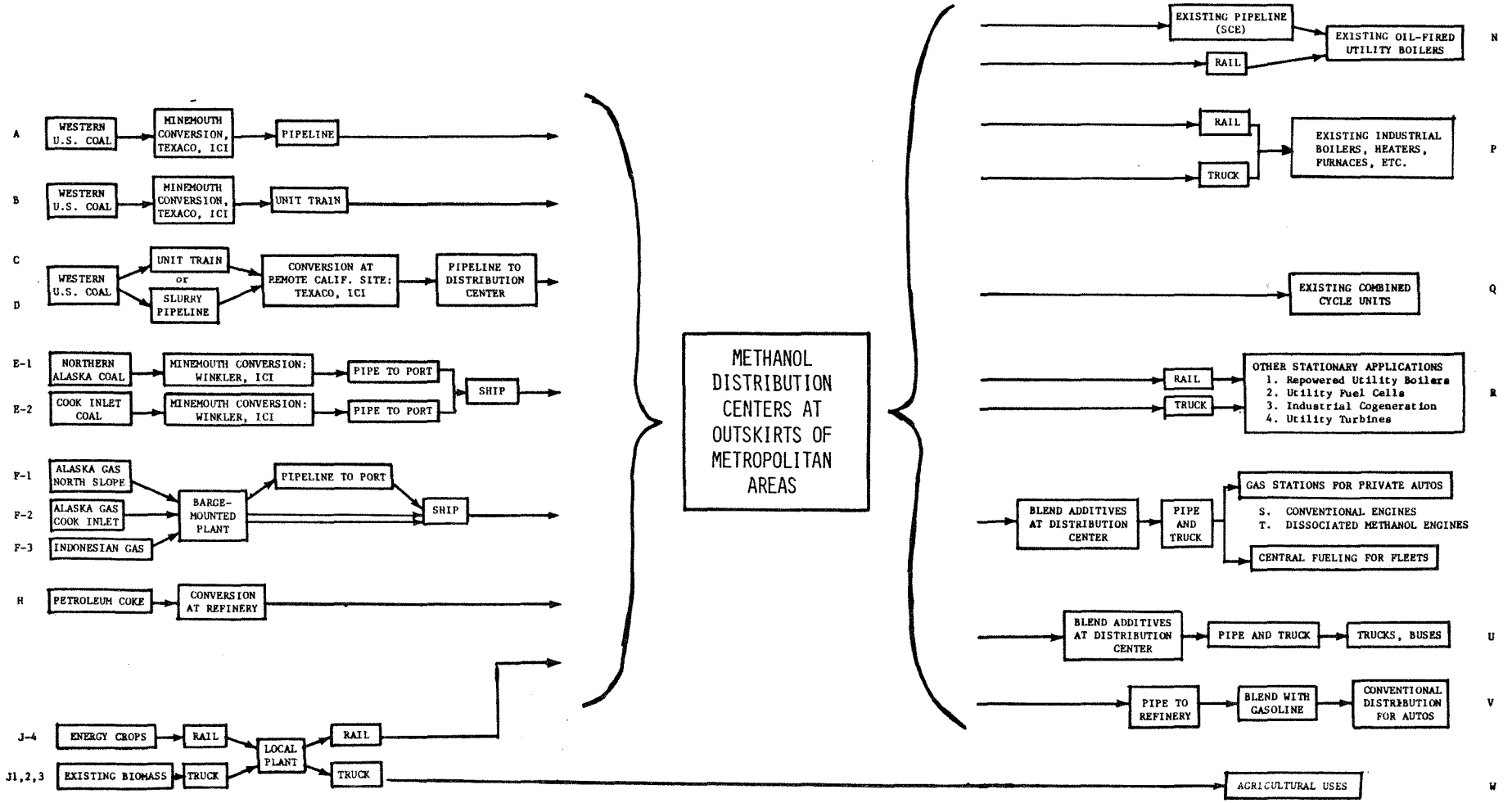


Figure 2-1. OVERVIEW OF METHANOL ENERGY DELIVERY SYSTEMS

cost and adding the value added for transport and conversion. The conversion cost computation method used in Chapter 4 assumes escalation of the methanol selling price at the same rate as for competing fuels so that competiveness in the first year of operation assures competitiveness over the life of the plant.

The focus of the demand worksheets is a target price for methanol at the distribution center which would make it competitive with the fuel currently used (or likely to be used). This was obtained by starting with the projected price of the competing fuel and subtracting out distribution costs, dealer mark-up, differences in efficiency, etc. The process of comparing the minimum required price at the distribution center with the target price to determine the competitiveness of methanol is illustrated in Figure 2-2.

1. CASE A: Western U.S. Coal/Minemouth Conversion/Pipeline Shipment

Western resources were divided among six regions, each with relatively uniform coal properties, feedstock cost, and transportation constraints (see Figure 3-3, p. 3-14). The total resource figures are those reported in Chapter 3. Strippable reserves identified in Chapter 3 are shown for comparison in Table 2-2.

Coal prices and projected escalation rates were taken from Reference 2 and substantiated via discussions with suppliers. A number of sensitivities on feedstock escalation rates were examined (see Chapter 4), although only the baseline case of constant real feedstock costs is summarized in this chapter. Fifty-five percent conversion efficiency was assumed, resulting in a feedstock cost per million Btu nearly double the coal price. Some potential constraints on the rate of expansion of coal mining were identified.

The estimated pipeline cost was taken from Chapter 5.

The value added in the conversion of coal-to-methanol was taken from the reference case in Chapter 4 for the Texaco gasification and ICI methanol synthesis combination sized at 10,000 tons/day.

The value added for conversion was combined with the feedstock and transport cost to obtain the minimum required price of methanol delivered to the California metropolitan area distribution center. The conversion cost was found to be the biggest part of the required methanol selling price and its sensitivity to such factors as plant size is investigated in Chapter 4.

2. CASE B: Western U.S. Coal/Minemouth Conversion/Unit Train of Tank Cars

The transport costs here are taken from Chapter 5. The first three coal-producing regions would require new railroad construction. The existing capacity for transport into California is represented as the unused capacity of the two rail lines connecting California with the coal regions. (The capacity estimates for cases B-4, B-5 and B-6 should not be added.)

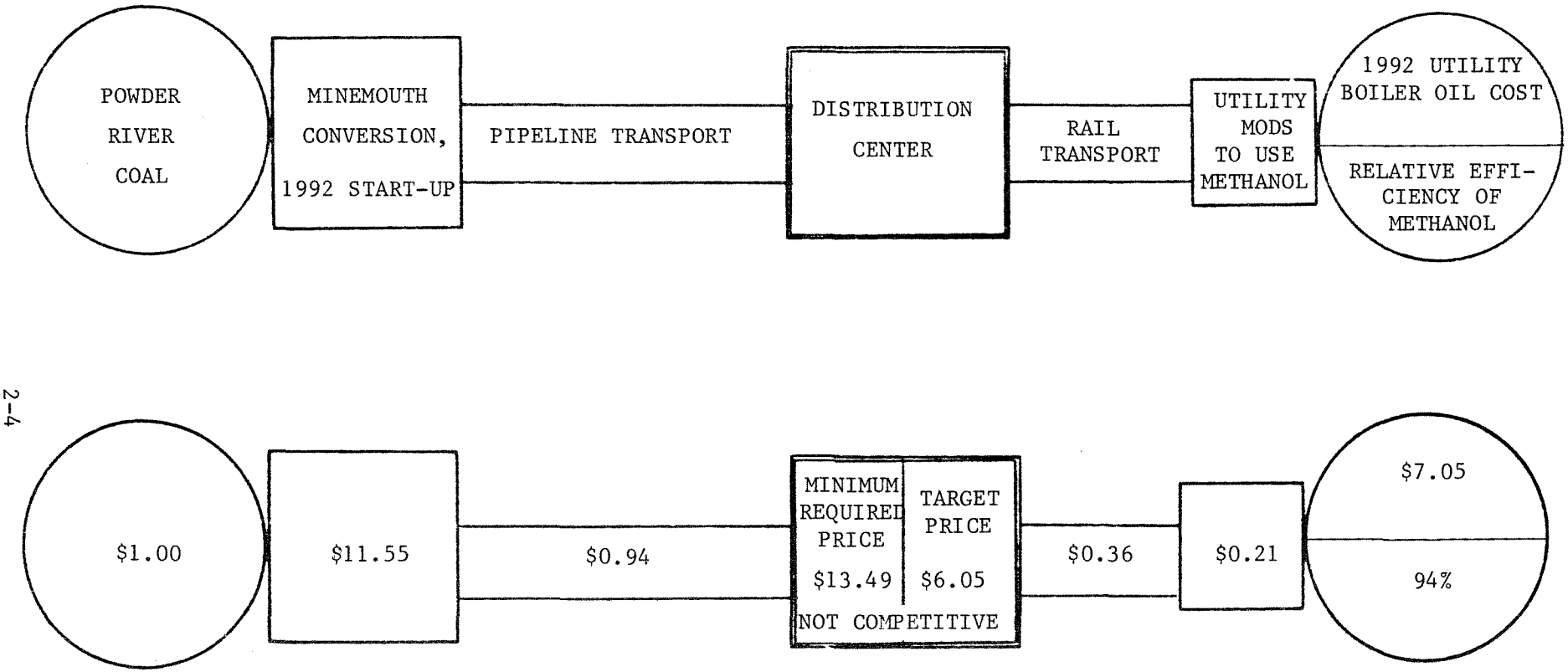


Figure 2-2. DETERMINATION OF COMPETITIVENESS
(All values in 1981 $/10^{6}Btu)

3. CASE C: Western U.S. Coal/Unit Train/California Conversion Plant/Pipeline to Distribution Center, and CASE D: Western U.S. Coal/Slurry Pipeline/California Conversion Plant/Pipeline to Distribution Center

These cases assume that any large coal-to-methanol plant located in California will have to be sited at a considerable distance from any metropolitan area, and that additional transport will be needed to convey the methanol from the plant to the distribution center.

4. CASE E: Alaska Coal/Minemouth Conversion/Pipeline to Port/Ship

Chapter 5 identifies enormous coal reserves in Northern Alaska (3.5 trillion tons) and moderate reserves in the Cook Inlet area which could present less of a logistics problem. Since the Northern Alaskan resource is currently of little value, the feedstock cost for methanol production was assumed equal to the cost of underground extraction (about $30/ton). However, this cost is based on Continental U.S. operations and could be much higher in Alaska. The feedstock cost for the Cook Inlet coal was based on estimates for the Beluga coal-to-methanol project.

In the Cook Inlet case, a port facility could be built at the conversion plant site. For Northern Alaska production, it was assumed that either a new pipeline would be built to a southern port or that connections would be made with the existing petroleum pipeline (availability of excess capacity is doubtful). No cost data were available to distinguish between these options.

The conversion economics are based on the Beluga project, which plans to use a Winkler gasifier with ICI synthesis (see Chapter 4).

5. CASE F: Remote Natural Gas/Barge-Mounted Conversion Plant/Pipeline to Port(Alaska North Slope only)/SHIP

Remote natural gas is defined here as gas for which pipeline shipment to market is impractical. Since the worldwide supplies of such gas are very large, it has zero opportunity cost and the cost to a methanol producer was set equal to an estimated extraction cost ($1/MBtu of gas). The Alaska pipeline considerations discussed in the preceding case also apply here. The conversion economics used here are for the Chapter 4 reference case for a barge-mounted plant sized at 3,000 tons/day.

6. CASE H: California Petroleum Coke/Conversion at Refinery

This is a straightforward case, but feedstock availability may be constrained by other uses within the refinery. Feedstock and conversion costs are from the reference case in Chapter 4.

7. CASE J: California Biomass/Truck or Rail/Local Conversion Plant/Truck or Rail/Local Uses or Central Distribution

For existing biomass resources, it is assumed that they will be converted in local plants and the resulting methanol will be used locally. For energy crops, which represent a potentially larger resource, rail transport and central methanol distribution were assumed.

Resource costs and energy crop quantities were taken from unpublished data compiled in the JPL Bioenergy Mission Analysis Task. Conversion economics are discussed in Chapter 4. The conversion costs in Chapter 4 were based on a conventional field-erected design. Recent studies by International Harvester have indicated that conversion costs can be reduced by use of small factory-assembled units drawing on biomass collected over a small area. Plant gate costs as low as $10/MBtu may be achievable.

Methanol users with tax liability can currently benefit from a "tax credit" for biomass-based methanol. The so-called "credit" is actually treated as a deduction and is worth $.20/gal ($3/MBtu) to a 50 percent tax bracket user.

8. CASE N: Existing Oil-Fired Utility Boilers/Supplied by Existing Pipeline System, Rail, or Ship (for coastal plants)

Projections of demand for this and all other stationary applications were taken from Chapter 9. Prices of oil and gas for the baseline and high oil price scenarios are discussed in the Summary Report. Prices for other alternative fuels were based on production costs in Chapter 4 and are summarized in Table 2-1. Natural gas is shown as a competing fuel for this and other utility cases, but its long-term availability is very uncertain.

Differences in efficiency when burning methanol, and costs of distribution and of modifications to existing facilities are discussed in Chapter 9. Distribution of methanol to existing utility boilers would be a complex problem. Several power plants are located on the coast with marine terminals for easy supply by ship. Southern California Edison (SCE), the largest potential methanol user, supplies about three-fourths of its oil through a network of pipelines. Other plants are supplied by rail and a few smaller ones by truck. The target prices for Case N are based on use of the SCE pipeline system, but they can be easily adjusted for other methods.

9. CASE P: Industrial Boilers and Heaters/Supplied by Rail or Truck

This case applies to industrial fuel use in boilers, process heaters, furnaces, etc. Both existing and new or replacement units are included. Some industries have low value by-products available as fuel (e.g., refineries) and others have narrow fuel specifications (e.g., steel makers) so that only a part of their energy use is included. Most of the considerations in establishing the target price are similar to those in the preceding case, except that these units generally use distillate oil rather than residual oil.

Table 2-1. SYNFUEL ALTERNATIVES

FUEL	OIL SHALE PRODUCTS		M-GASOLINE	FISCHER-TROPSCH GASOLINE	MBG	SNG	LNG	
	BOILER FUEL	GASOLINE					COOK INLET	INDONESIA
PLANT GATE COST (1981 $/10^6$ Btu)								
1987	9.57	12.60	13.33	17.32	9.28	9.46	4.74	5.30
1992	10.00	13.14	13.90	18.00	9.66	9.85	4.84	5.40
1997	10.40	13.70	14.41	18.99	10.22	10.31	5.37	5.93
AVG. MILES TO DISTRIBUTION CENTER	600	600	800	800	900/150	800	2000	8800
TRANSPORT METHOD	Pipeline	Pipeline	Pipeline	Pipeline	Train/ Pipeline	Pipeline	Ship	Ship
TRANSPORT COST (1981 $/10^6$ Btu)	.23	.28	.38	.38	1.11/2%	3%	1.16	2.78
PRICE AT DIST. CENTER (1981$/10^6$ Btu)								
1987	9.80	12.88	13.71	17.70	10.60	9.74	5.90	8.08
1992	10.23	13.42	14.28	13.38	10.99	10.15	6.00	8.18
1997	10.63	13.98	14.79	19.37	11.56	10.62	6.53	8.71

[a]Note the current methanol price is approximately $0.70/gal or nearly $11.00/$10^6$ Btu.

10. CASE Q: Existing Combined-Cycle Units

This is a special case of two SCE facilities that are viewed as likely near-term users among stationary applications because of their environmental sensitivity and relative simplicity of supply. Both are located at likely distribution centers: one at the port of Long Beach and the other at Cool Water, inland from the Los Angeles basin and adjacent to key rail lines. Modification costs are the same as for Case N.

11. CASE R: Other Stationary Applications/Supplied by Rail or Truck

This case includes several dissimilar applications that have similar target prices.

Repowering of existing steam turbine units to increase capacity, while improving efficiency and emissions is discussed in Chapter 9. The modification costs in the worksheet represent only the difference between repowering to burn methanol and repowering to burn oil.

Fuel cells have the potential to capture a portion of the utility peaking and intermediate load demand, although the economics are not clear at this time.

Utility peaking turbines could be a likely near-term methanol application, but fuel use is quite small and likely to remain so as a result of successful utility load management programs.

New industrial cogeneration units based on gas turbines could represent a substantial market for methanol. The demand shown here is only the electricity generation portion (the industrial use is included in Case P).

12. CASE S: Fleet and Private Neat Methanol-Fueled Cars and Light Trucks (Supplied by Conventional Methods with Additives Blended at Distribution Centers)

Demand and cost adjustment factors for this and other mobile application cases are discussed in detail in Chapter 8. Distribution costs are considered to be the same per gallon as gasoline, resulting in a difference per million Btus. Dealer mark-up and excise taxes are assumed to be the same per gallon for both fuels. The ratio of efficiencies in the worksheets, expressed in terms of higher heating value, are somewhat misleading. When expressed in terms of lower heating values (more commonly used by auto engine analysts) a more substantial improvement is found for methanol.

The worksheet lists a current fleet demand of 0.15 quads/year, but the near-term fleet market for methanol would be limited to about 0.01 quad/year by several factors, the most significant being the absence of a resale market (see Chapter 8).

13. CASE T: Fleet and Private Cars and Light Trucks with Dissociated Methanol Engines (Supplied by Conventional Methods with Additives Blended at Distribution Centers)

This case is essentially the same as Case S except that the vehicles would use advanced technology engines (e.g., dissociated methanol engines) to provide substantial efficiency improvements.

14. CASE U: Heavy Trucks and Buses Burning Neat Methanol (Supplied by Conventional Methods with Additives Blended at Distribution Centers)

The competing fuel is distillate (diesel oil). Methanol engine efficiency was assumed to be the same as diesel.

15. CASE V: A 4.5-Percent Methanol Blend with Gasoline for Existing Cars (Supplied by Pipeline for Blending at the Refinery)

There are three blending situations that result in different methanol target prices, with a further differentiation between regular and premium gasolines. The highest price would be paid by small refineries (toppers and hydro-skimmers) that must buy octane enhancers on the open market. An intermediate target price applies to an integrated refinery and is based on eliminating high value octane enhancers while adding methanol to maintain the same octane number. The low target price in the worksheets applies to a refinery that has an excess of octane enhancers and would use methanol only for its added volume. The target prices in the worksheet are derived in Chapter 8.

16. CASE W: Agricultural Uses (Supplied by Truck from Local Biomass Sources, Case J).

Agricultural applications now use a variety of fuels with gasoline being the most significant.

C. SUMMARY OF RESULTS

The supply and demand data from the worksheets are summarized for comparison purposes in Tables 2-2 and 2-3. The methanol target prices at the distribution center (Table 2-3) can be compared directly with the minimum required supply prices (Table 2-2).

Making these comparisons, the most obvious conclusion is that methanol will become competive with gasoline in automotive applications long before it is competitive with other fuels. In the baseline oil price scenario, methanol from remote gas should be competitive by 1990, but methanol from coal will be competitive only for advanced technology engines. In the high oil price scenario, the results indicated that coal-based methanol would compete with shale-based gasoline for the automotive market.

In the stationary applications sector, the situation is not nearly as promising for methanol. Methanol would play a role in this sector only under the high oil price scenario and then only if natural gas and LNG from remote gas are not available (an unlikely combination of circumstances).

In most cases, the resource quantities are sufficient for many decades of demand, but this is <u>not</u> true of Cook Inlet gas, which would be the source of the lowest priced methanol for California. It should be noted that some of the demand elements are substitutes for each other (e.g., turbines and fuel cells), and thus the quantities should not be added.

A further note of caution in regard to using the results in Tables 2-2 and 2-3 is that they represent averages and/or baseline cases for groups of methanol sources and applications that have much internal variation and can be very sensitive to a broad spectrum of variables. These variations and sensitivities are explored in the following chapters.

Table 2-2. METHANOL SUPPLY SUMMARY

RESOURCE	PRODUCTION/TRANSPORT	EXTENT OF RESOURCE (quads of methanol)		POTENTIAL PRODUCTION (quads/yr. of Methanol)	MINIMUM REQUIRED PRICE AT CALIFORNIA METROPOLITAN AREA DISTRIBUTION CENTER (1981 $/10^{6}Btu of Methanol)
		ESTIMATED	STRIPPABLE RESERVES		
A. Western U.S. Coal	Minemouth conversion/			very large	
1. Arizona	pipeline	500	10		13.60
2. Southern Utah		500	4		13.60
3. San Juan		1600	59		13.80
4. Central Utah, Piceance		4000	2		14.30
5. S. Wyoming, Yampa		7300	38		14.20
6. Powder River		5200	430		13.50
B. Western U.S. Coal	Minemouth conversion/			very large	
1. Arizona	rail	500	10		14.40
2. Southern Utah		500	4		14.40
3. San Juan		1600	59		14.70
4. Central Utah, Piceance		4000	2		15.30
5. S. Wyoming, Yampa		7300	38		15.40
6. Powder River		5200	430		15.10
C. Western U.S. Coal	Rail or slurry pipeline/			very large	
1. Arizona	Calif. conversion/	500	10		14.00
2. Southern Utah	pipeline	500	4		14.00
3. San Juan		1600	59		14.40
4. Central Utah, Piceance		4000	2		14.70
5. S. Wyoming, Yampa		7300	38		14.80
6. Powder River		5200	430		14.70
E. Alaskan Coal	Minemouth conversion/		56		
1. North Slope	pipeline/ship	31000		very large	19.40
2. Cook Inlet		500		large	18.20
F. Overseas Natural Gas					
1. Alaska North Slope	Barge-mounted plant/ pipeline/ship	25			11.20
2. Cook Inlet	Barge-mounted plant/ship	2.5			8.90
3. Indonesia	Barge-mounted plant/ship	10			10.30
H. Calif. Petroleum Coke	Conversion at refinery			0.50	16.50
J. Calif. Biomass					
1. Agricultural waste	Truck/local plant/truck			0.02	18.30(2)(3)
2. Wood waste	Truck/local plant/truck			0.005	17.50(2)(3)
3. Manure	Truck/local plant/truck			0.01	16.10(2)
4. Energy crops	Rail/local plant/rail			0.3	21.00(2)(3)

(1) Based on 1992 startup. Minimum required price in first year of operation increases at a rate of about 1 percent per year.
(2) Tax credit for biomass-based alcohol fuels can provide up to $3.00/10^{6}Btu benefit for users with tax liability. (Expires 1992.)
(3) Small-scale production in factory assembled process units may reduce the minimum required price to about $10/10^{6}Btu (at the production rate).

Table 2-3. SUMMARY OF METHANOL DEMAND AND TARGET PRICES

END USE	DEMAND (quads/yr. of methanol) 1980	1997	DISTRIBUTION METHOD	CURRENT OR COMPETING FUEL	METHANOL TARGET PRICE AT METROPOLITAN AREA DISTRIBUTION CENTER (1981 $/10^6 Btu of Methanol) 1987	1992	1997
N. EXISTING UTILITY BOILERS[1],[2]	0.9	0.6	Pipeline (ship, rail)	1. Residual oil, baseline	5.56	6.60	7.40
				2. Residual oil, high oil price	6.10	8.10	10.20
				3. Fuel oil from shale	8.90	9.30	9.70
				4. Natural gas, baseline	5.10	6.25	7.00
				5. Natural gas, high oil price	5.30	7.00	8.80
				6. LNG (Cook Inlet)	5.50	5.60	6.10
				7. LNG (Indonesia)	7.60	7.70	8.20
				8. SNG	9.30	9.70	10.10
				9. MBG	10.10	10.50	11.00
P. EXISTING INDUSTRIAL BOILERS AND REPLACEMENTS[3]	0.6	0.6	Rail (truck)	1. Distillate oil, baseline	5.80	7.40	8.70
				2. Distillate oil, high oil price	7.50	10.10	12.70
				3. Distillate oil from shale	12.20	12.80	13.30
				4. Natural gas, baseline	4.80	6.00	6.80
				5. Natural gas, high oil price	5.00	6.70	8.50
				6. LNG (Cook Inlet)	5.20	5.30	5.80
				7. SNG	9.00	9.40	9.80
Q. EXISTING UTILITY COMBINED CYCLE PLANTS	0.03	0.04	(located at dist. centers)	1. Distillate oil, baseline	6.50	8.20	9.60
				2. Distillate oil, high oil price	8.40	11.20	13.90
				3. Distillate oil from shale	13.40	14.00	14.60
R. OTHER STATIONARY APPLICATIONS[3]			Rail(truck)	4. Natural gas, baseline	5.30	6.50	7.30
- Repowered utility boilers	0.9	0.6		5. Natural gas, high oil price	5.50	7.20	9.10
- Utility fuel cells	0	0.2		6. LNG (Cook Inlet)	5.70	5.80	6.30
- Industrial cogeneration	0	0.1		7. SNG	9.50	9.90	10.40
- Utility turbines	0.005	0.005					
S. METHANOL CARS AND LIGHT TRUCKS			Blend at dist. center/pipe or truck	1. Gasoline, baseline	8.50	10.70	12.00
- Private	1.5	1.0		2. Gasoline, high oil price	10.20	14.20	17.20
- Fleets[4]	0.15	0.15		3. Gasoline from shale	13.00	13.30	13.40
				4. M-gasoline	13.90	14.20	14.30
T. DISSOCIATED METHANOL CARS AND LIGHT TRUCKS	1.65	1.15	Blend at dist. center/pipe or truck	1. Gasoline, baseline	-	12.80	14.30
				2. Gasoline, high oil price	-	16.90	20.40
				3. Gasoline from shale	-	15.80	16.10
				4. M-gasoline	-	16.90	17.00
U. HEAVY TRUCKS AND BUSES	0.3	0.6	Blend at dist. center/pipe or truck	1. Distilate oil baseline	6.60	8.30	9.70
				2. Distillate, high oil price	8.50	11.20	13.90
				3. Distillate oil from shale	13.50	14.00	14.60
V. GASOLINE CARS (4.5% blend)[5]			Pipeline to refinery/ blend/conventional distribution	Gasoline, baseline			
1. Volume blending, regular	0.05	0.04			9.90	13.00	15.30
2. Volume blending, premium	0.02	0.02			11.50	15.20	17.80
3. Octane blending, regular	0.05	0.04			14.00	18.50	21.00
4. Octane blending, premium	0.02	0.02			15.70	20.00	24.10
5. Toppers and hydro-skimmers	0.003	0.002			17.30	22.80	26.70
W. AGRICULTURAL USES	0.03	0.03	Truck from local plant	1. Gasoline, baseline	8.10	10.40	12.10
				2. Gasoline, high oil price	10.20	13.90	18.10

[1] Increase target price by $.10 for coastal plants.
[2] Decrease target price by $.30 for rail distribution.
[3] Decrease target price by $.25 for truck distribution.
[4] Near term use in fleets will not exceed 0.01 quads.
[5] Assumes availability of inexpensive co-solvent

D. REFERENCES

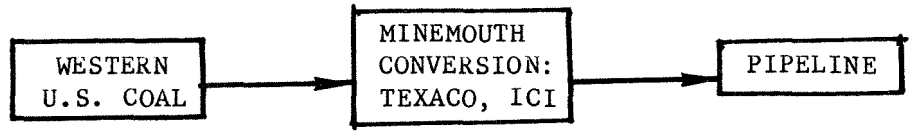
1. Ferm, J. C. and Muthig, P. J., A Study of the United States Coal Resources, JPL Publication (number to be assigned), December 15, 1981.

2. Terasawa, K. L. and Whipple, D. W., Regional Price Targets Appropriate for Advanced Coal Extraction, JPL Publication 80-91, December 1, 1980.

ADDENDUM

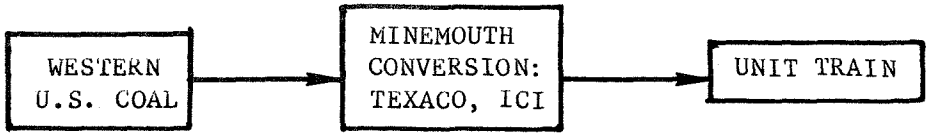
WORKSHEETS

A

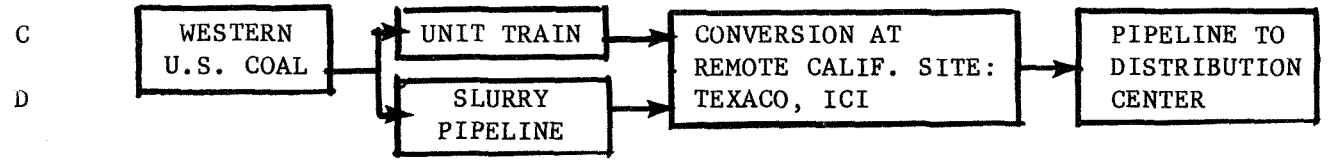


	A-1 Ariz.	A-2 So. Utah	A-3 San Juan	A-4 Cent. UT Piceance	A-5 So. WY Yampa	A-6 Powder River
RESOURCE						
Total Resource	500	500	1600	4000	7300	5200
Strippable Reserves	10	4	59	2	38	430
Current Production/Availability	0.1	0.0	0.1	0.3	0.3	0.5
Limits on Rate of Expansion	Committed	Envirnmtl.				
Land Ownership	No RR Indians	No RR Federal	No RR Indians	Oil Shale Federal Private	Federal Private	Federal Private
Coal Price ($/10^6 Btu Coal)	.85	.85	.90	1.20	1.10	.55
Feedstock Cost ($/10^6 Btu Methanol)	1.55	1.55	1.64	2.18	2.00	1.00
TRANSPORT						
Avg. Miles to Market or Conv. Plant	500	500	600	600	700	1000
Current Capacity	0	0	0	0	0	0
Current Value Added	.47	.47	.56	.56	.66	.94
CONVERSION						
Current Capacity	0	0	0	0	0	0
Limits on Rate of Expansion		Capital Formation				
Value Added ($/10^6 Btu)	11.55	11.55	11.55	11.55	11.55	11.55
MINIMUM REQUIRED PRICE OF FUEL FOR 1992 START-UP (Delivered to Calif. Metropolitan Areas in 1981 $/10^6 Btu methanol)	13.57	13.57	13.75	14.29	14.21	13.49

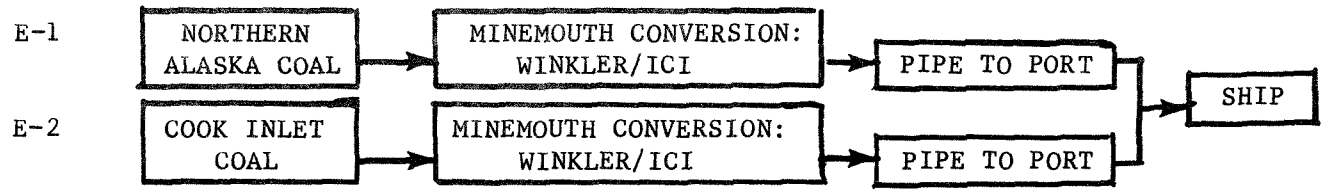
B



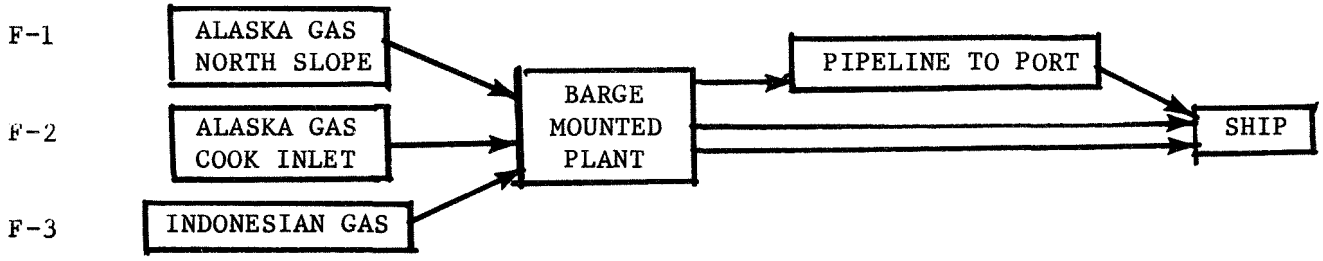
	B-1 Ariz.	B-2 So. Utah	B-3 San Juan	B-4 Cent. UT Piceance	B-5 So. WY Yampa	B-6 Powder River
RESOURCE						
Total Resource	500	500	1600	4000	7300	5200
Strippable Reserves	10	4	59	2	38	430
Current Production/Availability	0.1	0.0	0.1	0.3	0.3	0.5
Limits on Rate of Expansion	Committed	Envirnmtl.				
Land Ownership	No RR Indians	No RR Federal	No RR Indians	Oil Shale Federal Private	Federal Private	Federal Private
Coal Price ($/MBTU Coal)	.85	.85	.90	1.20	1.10	.55
Feedstock Cost ($/$10^6$ Btu methanol)	1.55	1.55	1.64	2.18	2.00	1.00
TRANSPORT						
Avg. Miles to Market or Conv. Plant	650	650	780	780	910	1300
Current Capacity	0	0	0	.8	.6	.6
Value Added ($/$10^6$ Btu)	1.29	1.29	1.54	1.54	1.80	2.57
CONVERSION						
Current Capacity	0	0	0	0	0	0
Limits on Rate of Expansion		Capital Formation				
Value Added ($/$10^6$ Btu)	11.55	11.55	11.55	11.55	11.55	11.55
MINIMUM REQUIRED PRICE OF FUEL (Delivered to Calif. Metropolitan Areas in 1981 $/$10^6$ Btu methanol)	14.39	14.39	14.73	15.27	15.35	15.12



	C-1 D-1 Ariz.	C-2 D-2 So. Utah	C-3 D-3 San Juan	C-4 D-4 Cent. UT Piceance	C-5 D-5 So. WY Yampa	C-6 D-6 Powder River
RESOURCE						
Total Resource	500	500	1600	4000	7300	5200
Strippable Reserves	10	4	59	2	38	430
Current Production/Availability	0.1	0.0	0.1	0.3	0.3	0.5
Limits on Rate of Expansion	Committed	Envirnmtl.				
Land Ownership	No RR Indians	No RR Federal	No RR Indians	Oil Shale Federal Private	Federal Private	Federal Private
Coal Price ($/10^6 Btu Coal)	.85	.85	.90	1.20	1.10	.55
Feedstock Cost ($/10^6 Btu methanol)	1.55	1.55	1.64	2.18	2.00	1.00
TRANSPORT						
Avg. Miles to Market or Conv. Plant	500/150	500/150	630/150	630/150	760/150	1150/150
Current Capacity	0	0	0	.8/0	.6/0	.6/0
Value Added ($/10^6 Btu)	.73/.14	.73/.14	1.08/.14	.81/.14	1.11/.14	1.97/.14
CONVERSION						
Current Capacity	0	0	0	0	0	0
Limits on Rate of Expansion		Capital Formation				
Value Added ($/10^6 Btu)	11.55	11.55	11.55	11.55	11.55	11.55
MINIMUM REQUIRED PRICE OF FUEL (Delivered to Calif. Metropolitan Areas in 1981 $/10^6 Btu)	13.97	13.97	14.41	14.68	14.80	14.66

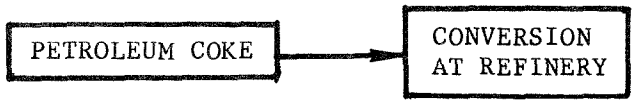


	E-1	E-2
RESOURCE		
Total Resource	31,000	500
Strippable Reserves	56	
Current Production/Availability	0	0
Cost (Extraction Cost in $/10^6 Btu methanol)	3.00	2.50
TRANSPORT		
Avg. Miles to Market or Conv. Plant	800/2000	50/2000
Current Capacity	0	0
Limits on Rate of Expansion	Use of Pipeline	Port Facilities
Value Added ($/10^6 Btu)	.75/.77	.05/.77
CONVERSION		
Current Capacity	0	0
Value Added ($/10^6 Btu)	14.90	14.90
MINIMUM REQUIRED PRICE OF FUEL (Delivered to Calif. Metropolitan Areas in 1981 $/10^6 Btu)	19.42	18.22



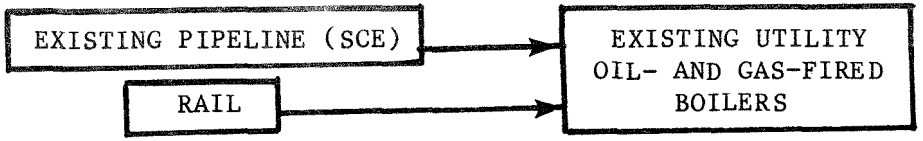
	F-1	F-2	F-3
RESOURCE			
Reserves	25	2.5	10
Current Production/(mostly reinjected)	0.3	0.05	0
Cost (Extraction & Collection (in $/10^6 Btu of methanol)	1.70	1.70	1.70
Projected Real Escalation (%/Yr.)	0	0	0
Ownership	Federal	State	
TRANSPORT			
Avg. Miles to Market or Conv. Plant	800/2000	2000	8800
Current Capacity	0	0	0
Limits on Rate of Expansion	Unloading Capacity		
Value Added ($/10^6 Btu)	.75/.77	.77	2.16
CONVERSION			
Current Capacity			
Value Added ($/10^6 Btu)	9.70	6.47	6.47
MINIMUM REQUIRED PRICE OF FUEL (Delivered to Calif. Metropolitan Areas in 1981 $/10^6 Btu)	11.22	8.94	10.33

H



	H-1
RESOURCE	
Current Production/Availability (10^6Btu/yr of methanol)	.01
Potential Production/Availability (10^6Btu/yr of methanol)	.5
Limits on Rate of Expansion	Other Uses
Cost ($/$10^6$ Btu of methanol)	3.27
Projected Real Escalation (%/Yr.)	0
TRANSPORT	
Avg. Miles to Market or Conv. Plant	0
Value Added	0
CONVERSION	
Value Added ($/$10^6$ Btu)	13.21
MINIMUM REQUIRED PRICE OF FUEL (Delivered to Calif. Metropolitan Areas in 1981 $/$10^6$ Btu of methanol)	16.48

	1 Agric. Waste	2 Wood Waste	3 Manure	4 Energy Crops
RESOURCE				
Current Production/Availability	.02	.005	.01	0
Potential Production/Availability	.02	.005	.01	.3
Limits on Rate of Expansion				Land Availability
Cost (production and/or collection in $/10^6$ Btu of methanol)	2.60	1.80	.35	5.20
TRANSPORT				
Avg. Miles to Market or Conv. Plant	50/50	50/50	50/50	100/200
Value Added ($/10^6$ Btu)	.97/.10	.97/.10	.97/.10	.97/.17
CONVERSION				
Current Capacity	0	0	0	0
Value Added ($/10^6$ Btu)	14.63	14.63	14.63	14.63
MINIMUM REQUIRED PRICE OF FUEL (Delivered to Calif. Metropolitan Areas (energy crops) or local users, in 1981 $/10^6$ Btu methanol)	18.30	17.50	16.05	20.97
TAX CREDIT FOR USERS WITH TAX LIABILITY	(3.00)	(3.00)	(3.00)	(3.00)
MINIMUM PRICE AFTER-TAX CREDIT	15.30	14.50	13.05	17.97



CASE N

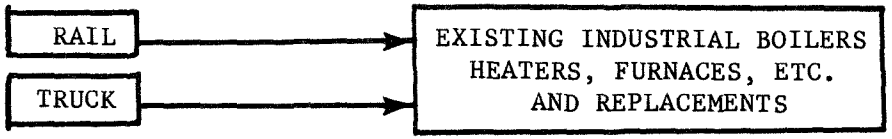
DISTRIBUTION			
Method	existing pipeline	rail	coastal
Avg. mi. from Dist. Center	100	100	0
Current Capacity (quads/yr)	large (SCE)	medium	large
Value Added: Difference For Methanol (1981 $/10^6 Btu)	.09	.36	0
Limits on Rate of Expansion	logistics	mountain passes	

FUEL USE (Quads/year)	
Current	0.9
1997	0.6

TARGET PRICE FACTORS

COMPETING FUEL		RESIDUAL OIL, BASELINE	RESIDUAL OIL, HIGH	BOILER FUEL FROM SHALE	GAS, BASELINE	GAS, HIGH	LNG CI	LNG INDO.	MBG	SNG
Price of Competing Fuel (1981 $/10^6 Btu)	1987	6.23	6.78	9.80	5.51	5.70	5.90	8.08	10.60	9.74
	1992	7.37	8.95	10.23	6.68	7.45	6.00	8.18	10.99	10.15
	1997	8.20	11.18	10.63	7.48	9.30	6.53	8.71	11.56	10.62
Ratio of Efficiencies (Methanol/Competing Fuel)		.94	.94	.94	.98	.98	.98	.98	.98	.98
Other Adjustments (1981 $/10^6 Btu)										
Pipeline Distribution		.09	.09	.09	.09	.09	.09	.09	.09	.09
Boiler & Fac. Modification		.21	.21	.21	.21	.21	.21	.21	.21	.21
TARGET PRICE* (1981 $/10^6 Btu)										
	1987	5.56	6.07	8.91	5.10	5.28	5.48	7.62	10.09	9.25
	1992	6.63	8.11	9.32	6.25	7.00	5.58	7.72	10.47	9.65
	1997	7.41	10.21	9.69	7.03	8.81	6.10	8.24	11.03	10.11

*At Central Distribution Center (see Figure 2-2).



CASE P

DISTRIBUTION		
Method	rail	truck
Avg. mi. from Dist. Center	100	100
Current Capacity (quads/yr)	medium	medium
Value Added: Difference For Methanol (1981 $/10^6 Btu)	.36	.61
Limits on Rate of Expansion	mountain passes	

FUEL USE (Quads/year)	
Current	0.6
1997	0.6

TARGET PRICE FACTORS

Competing Fuel		DISTILLATE, BASELINE	DISTILLATE, HIGH	DISTILLATE, FROM SHALE	GAS, BASELINE	GAS, HIGH	LNG CI	LNG INDO.	MBG	SNG
Price of Competing Fuel (1981 $/10^6 Btu)	1987	6.77	8.61	13.63	5.51	5.70	5.90	8.08	10.60	9.74
	1992	8.45	11.38	14.20	6.68	7.45	6.00	8.18	10.99	10.15
	1997	9.84	14.08	14.80	7.48	9.30	6.53	8.71	11.56	10.62
Ratio of Efficiencies (Methanol/Competing Fuel)		.94	.94	.94	.98	.98	.98	.98	.98	.98
Other Adjustments (1981 $/10^6 Btu)										
Rail Distribution		.36	.36	.36	.36	.36	.36	.36	.36	.36
Modifications		.21	.21	.21	.21	.21	.21	.21	.21	.21
TARGET PRICE* (1981 $/10^6 Btu)										
	1987	5.79	7.52	12.24	4.83	5.02	5.21	7.35	9.82	8.98
	1992	7.37	10.13	12.78	5.98	6.73	5.31	7.45	10.20	9.38
	1997	8.68	12.67	13.34	6.76	8.54	5.83	7.97	10.76	9.84

*At Central Distribution Center (see Figure 2-2).

CASE Q - Existing Combined Cycle Units (Long Beach and Cool Water)

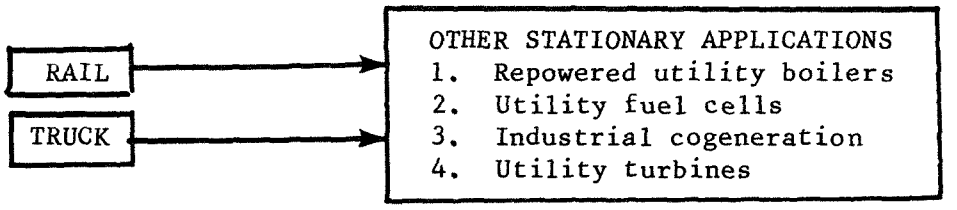
DISTRIBUTION	
Method	Not applicable (located at distribution center)
Avg. mi. from Dist. Center	0
Current Capacity (quads/yr)	
Value Added: Difference For Methanol (1981 $/10^6 Btu)	0

FUEL USE (Quads/year)	
Current	0.03
1997	0.04

TARGET PRICE FACTORS

Competing Fuel		DISTILLATE, BASELINE	DISTILLATE, HIGH	DISTILLATE, FROM SHALE	GAS, BASELINE	GAS, HIGH	LNG CI	LNG INDO.	MBG	SNG
Price of Competing Fuel (1981 $/10^6 Btu)	1987	6.77	8.61	13.63	5.51	5.70	5.90	8.08	10.60	9.74
	1992	8.45	11.38	14.20	6.68	7.45	6.00	8.18	10.99	10.15
	1997	9.84	14.08	14.80	7.48	9.30	6.53	8.71	11.56	10.62
Ratio of Efficiencies (Methanol/Competing Fuel)		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Other Adjustments (1981 $/10^6 Btu)										
Modifications		.21	.21	.21	.21	.21	.21	.21	.21	.21
TARGET PRICE* (1981 $/10^6 Btu)										
1987		6.56	8.40	13.42	5.30	5.49	5.69	7.87	10.39	9.53
1992		8.24	11.17	13.99	6.47	7.24	5.79	7.97	10.78	9.94
1997		9.63	13.87	14.59	7.27	9.09	6.32	8.50	11.35	10.41

*At Central Distribution Center (see Figure 2-2).



CASE R

DISTRIBUTION

	rail	truck
Method		
Avg. mi. from Dist. Center	100	100
Current Capacity (quads/yr)	medium	medium
Value Added: Difference For Methanol (1981 $/10^6 Btu)	.36	.61
Limits on Rate of Expansion	mountain passes	

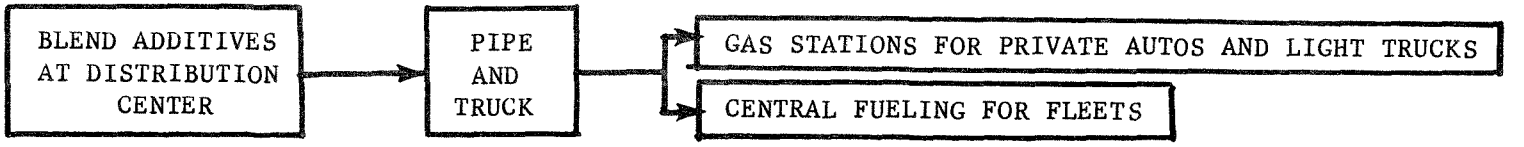
FUEL USE (Quads/year)

	REPOWERED UTILITY BOILERS	UTILITY FUEL CELLS	INDUSTRIAL COGENERATION	UTILITY
Current	0.9	0	0	.005
1997	0.6	0.2(?)	0.1	.005

TARGET PRICE FACTORS

Competing Fuel		DISTILLATE, BASELINE	DISTILLATE, HIGH	DISTILLATE, FROM SHALE	GAS, BASELINE	GAS, HIGH	LNG CI	LNG INDO.	MBG	SNG
Price of Competing Fuel (1981 $/10^6 Btu)	1987	6.77	8.61	13.63	5.51	5.70	5.90	8.08	10.60	9.74
	1992	8.45	11.38	14.20	6.68	7.45	6.00	8.18	10.99	10.15
	1997	9.84	14.08	14.80	7.48	9.30	6.53	8.71	11.56	10.62
Ratio of Efficiencies (Methanol/Competing Fuel)		1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Other Adjustments (1981 $/10^6 Btu)										
Rail Distribution		.36	.36	.36	.36	.36	.36	.36	.36	.36
Modifications		.05	.05	.05	.05	.05	.05	.05	.05	.05
TARGET PRICE* (1981 $/10^6 Btu)										
	1987	6.50	8.37	13.49	5.21	5.40	5.61	7.83	10.40	9.53
	1992	8.21	11.20	14.07	6.40	7.19	5.71	7.93	10.80	9.94
	1997	9.63	13.95	14.69	7.23	9.08	6.25	8.47	11.38	10.42

*At Central Distribution Center (see Figure 2-2).



CASE S - CONVENTIONAL ENGINES OPTIMIZED FOR NEAT METHANOL
T - ADVANCED METHANOL ENGINES

DISTRIBUTION

Current Capacity (quads/yr)	large
Value Added: Difference For Methanol (1981 $/10^6 Btu)	.31

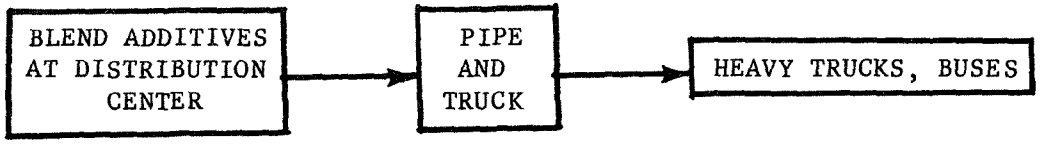
FUEL USE (Quads/year)

	PRIVATE AUTOS AND LIGHT TRUCKS	FLEETS
Current	1.5	.15
1997	1.0	.15
Limits on Rate of Expansion		resale market

TARGET PRICE FACTORS

		CASE S				CASE T			
Competing Fuel		GASOLINE BASELINE	GASOLINE HIGH	SHALE GASOLINE	M-GASOLINE	GASOLINE BASELINE	GASOLINE HIGH	SHALE GASOLINE	M-GASOLINE
Price of Competing Fuel (1981 $/10^6 Btu) HHV (retail)	1987	10.80	12.96	15.23	16.11	10.80	12.96	15.23	16.11
	1992	13.20	16.72	15.80	16.71	13.20	16.72	15.80	16.71
	1997	14.88	20.24	16.40	17.26	14.88	20.24	16.40	17.26
Ratio of Efficiencies* (Methanol/Competing Fuel)	1987	1.08	1.08	1.08	1.08	1.27	1.27	1.27	1.27
	1992	1.06	1.06	1.06	1.06	1.23	1.23	1.23	1.23
	1997	1.03	1.03	1.03	1.03	1.20	1.20	1.20	1.20
Other Adjustments (1981 $/10^6 Btu)									
Additives		.50	.50	.50	.50	.50	.50	.50	.50
Distribution		.31	.31.	.31	.31	.31	.31	.31	.31
Dealer markup		.77	.77	.77	.77	.77	.77	.77	.77
Excise tax		.85	.85	.85	.85	.85	.85	.85	.85
Sales tax		6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
TARGET PRICE** (1981 $/10^6 Btu)	1987	8.53	10.72	13.02	13.91	-	-	-	-
	1992	10.71	14.22	13.30	14.21	12.82	16.89	15.82	16.87
	1997	11.97	17.15	13.44	14.27	14.34	20.38	16.05	17.02

*These efficiency improvements of 8%, 6% and 3% for 1987, 1992 and 1997 in higher heating value correspond to 15%, 12% and 10%, respectively, for lower heating values.
**At Central Distribution Center (see Figure 2-2).

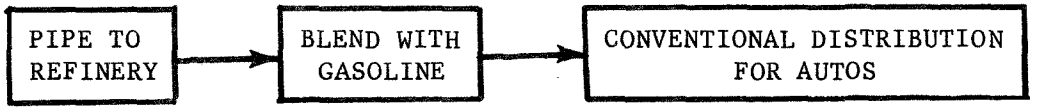


CASE U

DISTRIBUTION	
Current Capacity (quads/yr)	large
Value Added: Difference For Methanol (1981 $/10^6 Btu)	.16

FUEL USE (Quads/year)	
Current	0.3
1997	0.6

TARGET PRICE FACTORS				
Competing Fuel		DISTILLATE, BASELINE	DISTILLATE, HIGH	DISTILLATE, FROM SHALE
Price of Competing Fuel (1981 $/10^6 Btu) (wholesale)	1987	6.77	8.61	13.63
	1992	8.45	11.38	14.20
	1997	9.84	14.08	14.80
Ratio of Efficiencies (Methanol/Competing Fuel)		1.0	1.0	1.0
Other Adjustments (1981 $/10^6 Btu)				
Distribution		.16	.16	.16
TARGET PRICE (1981 $/10^6 Btu)				
1987		6.61	8.45	13.47
1992		8.29	11.22	14.04
1997		9.68	13.92	14.64



CASE V

	1 VOLUME BLENDING, REGULAR	2 VOLUME BLENDING, PREMIUM	3 OCTANE BLENDING, REGULAR	4 OCTANE BLENDING, PREMIUM	5 TOPPERS AND HYDRO-SKIMMERS
FUEL USE (Quads/yr)					
Current	.05	.02	.05	.02	.003
1997	.04	.02	.05	.02	.002
Limits on Rate of Extension	← Cosolvent Availability →				

TARGET PRICE (1981 $/10^6 Btu)	BASELINE	HIGH	BASELINE	HIGH	BASELINE	HIGH	BASELINE	HIGH	BASELINE	HIGH
1987	9.89	11.83	11.53	18.80	14.01	16.76	15.65	18.73	17.30	10.70
1992	13.03	16.63	15.20	19.40	18.46	23.56	20.63	26.33	22.80	29.11
1997	15.25	20.61	17.79	24.04	21.60	29.19	24.14	32.62	26.68	36.06

CASE W

DISTRIBUTION	
Method	Truck
Avg. mi. from Dist. Center	25
Current Capacity (quads/yr)	large
Value Added: Difference For Methanol (1981 $/10^6 Btu)	.05

FUEL USE (Quads/year)	
Current	.03
1997	.03

TARGET PRICE FACTORS		GASOLINE BASELINE	GASOLINE HIGH
Competing Fuel			
Price of Competing Fuel	1987	8.21	10.24
(1981 $/10^6 Btu)	1992	10.46	13.77
(wholesale)	1997	12.04	17.75
Ratio of Efficiencies (Methanol/Competing Fuel)		1.05	1.05
Other Adjustments (1981 $/10^6 Btu)			
Distribution		.05	.05
Additives		.50	.50
TARGET PRICE (1981 $/10^6 Btu)			
1987		8.07	10.20
1992		10.43	13.91
1997		12.09	18.09

CHAPTER THREE

ENERGY FEEDSTOCK SOURCES FOR METHANOL

Potential raw material resources for methanol production were identified, characterized, and quantified. Resources identified were those within California or readily accessible to California, and applicable for methanol production systems contributing significantly to California's liquid fuels supply. Established and potential conventional resources (natural gas, petroleum, petroleum coke, coal, and biomass residues), and unconventional resources (heavy petroleum shale oil, and bioenergy crops) were addressed. The most promising methanol alternatives appear to be those which utilize coal or natural gas feedstocks at the source, or en route to California.

A. INTRODUCTION

The purpose of this subtask was to provide identification and quantification of the potential energy resources that may be used as feedstocks for the production of methanol for California, and to provide a tabulation of the quantities and locations of the energy resources. This display of methanol resources according to availability is intended to aid in economic, technical, and policy analysis of alternative end-to-end methanol production systems.

Methanol feedstocks will critically influence the location, production process, product distribution, and scope of the methanol industry. The feedstock resource, in effect, may become the principal determinant of the nature of the industry. This overview is intended to guide resource considerations for preliminary feedstock selection; a more focused examination of the preferred candidate resources follows the selection of preferred options.

1. Approach

The study concentrated upon major industrial resource availabilities, distinct from the smaller-scale, regional resources that might support "neighborhood" production. Although small-scale, local methanol production facilities may be feasible, the diversity and scattered nature of local resources defies the scope of the study. Starting with current methanol feedstocks, such as natural gas, the study ranged through the likely raw materials occurring in the state and in areas capable of supplying methanol feedstocks, with some broad concern for economics. LNG from Africa and from Saudi Arabia was not considered among the candidates, nor was coal from Colombia or Appalachia; it seemed probable that in addition to unfavorable transport economies, these resources would be sought by competitive users.

The description of raw material resources potentially available for methanol production was based upon the existing literature and a familiarity with the state's geography and its natural resources. The study commenced with a survey of the extensive literature describing the classic processes and the raw materials adopted elsewhere in the world's methanol industries.

Data and conclusions relative to coal resources were derived from an active research program conducted by JPL for the U.S. Department of Energy and dedicated to the definition and design of advanced underground coal mining systems. A significant component of that program enlisted the University of Kentucky to assess and classify both surface and underground U.S. coals according to mining conditions. The resulting basin-by-basin study fully describes the western coals potentially available for methanol production. Supporting information was obtained from the 1981 Keystone Coal Industry Manual, other coal resources publications, and discussions with coal company representatives.

Data concerning California's biomass resources for methanol production were drawn mostly from information published by the State of California. Natural gas, petroleum, and unconventional petroleum resource data were taken from publications issued by the California Oil & Gas Division, Department of Conservation.

The study screened candidate raw materials for California methanol production against a framework of criteria that specified the nature and characteristics of the desirable feedstocks. In this consideration, the influences of economics and process selection were excluded from the resource considerations, and were purposely left to other chapters of this study.

In order to determine feedstock candidates worthy of consideration, it was decided that, as prerequisites, the acceptable methanol raw material candidate should:

- Be a carbon-based substance, natural or synthetic, having molecular chemistry that makes carbon exothermally available to the methanol molecule simply or with few process steps and, preferably, that provides hydrogen in association with the available carbon.

- Permit conversion of the raw material feedstock molecules to the methanol molecules with a significant net gain to energy.

- Be reliably consistent in nature and in chemistry.

- Be regular in supply.

- Be abundant in California or abundantly available to California by secure means of transportation.

In order to display the spectrum of methanol raw material candidates for consideration in California's evaluation, a classification system was devised. Two main classes were created to distinguish between "established" and "potential" resources. The established are taken as those now flowing, or immediately ready to flow; potentials are those that probably exist in the measures indicated and have potential if technology and economics permit exploitation. The established resources can be quantified with reasonable accuracy; the potentials tend to be hypothetical, and are subject to additions from discovery, consumption draw-down and recovery limitations.

A principal subgrouping separates each main class into the conventional resources and the unconventional. Each subgroup thereafter has been divided into domestic and imported (i.e., outside California) raw materials.

The following sections of the report provide an overview of California's resources in order to establish a background against which candidates can be evaluated as part of a range of options, together with descriptions and classifications of the potential resources.

B. OVERVIEW

An analysis of California's potential methanol raw materials, without reference to economics, longevity of supply, centralization of resources and political controls, can view a wide array and generous supply of candidates. The state has been among the leading producers of crude oil in the United States, has been a major natural gas supplier, and has a large production of biomass incidental to crop and forestry harvests. However, the forces that make methanol production worthy of consideration at this time are also those forces that have worked to make California an energy importing region; the state's population and energy demands have increased, its fossil fuel resources are being depleted, and its energy imports are becoming more costly. Moreover, the time frame required for a widespread introduction of methanol for significant substitution implies a continuation of these trends. Accordingly, California's energy future, including methanol production and use potential, must increasingly rely on non-California feedstocks.

In 1978, the state produced only about one-third of its petroleum consumption. It was part of a pattern that had seen the state's consumptions grow, productions wane, and resource discoveries diminish. Imports grew to fill the gap. In 1981, the official estimate of the state's recoverable petroleum resources stood at about 5 billion barrels. These resources are being drawn down at the rate of about one million barrels daily by production.

California's domestic natural gas resource declined through the 1970s. Currently, California has about 4 trillion cubic feet of natural gas resources. Natural gas consumption in the state is about 4.7 billion cubic feet/day; 1 billion cubic feet/day is produced in the state, and the rest is imported. Import supply potentials are very great, and given stimulating prices, a generous supply to California seems assured during the remainder of this decade.

Coal available to California in nearby states is generous. A recently completed JPL/University of Kentucky study identified a potential 900 billion tons of bituminous and subbituminous coals in Arizona, New Mexico, Colorado, and Utah; about one-half of this resource is mineable. This is the "front tier" of significant coal resources that might support methanol production for California. Beyond, in a second tier of states, a potential 1.4 trillion tons, mostly subbituminous and lignite, occur in North Dakota, Montana, and Wyoming. These resource estimates are derived from a geologic interpretation of the coal-bearing basins of the western United States.

Coal occurs in many counties in California as a mineral phenomenon, but only in five counties as significant deposits. The total resource identified is 90 million tons, mostly lignite in unfavorable mining environments.

Biomass resoures are significant in California as a result of extensive agricultural and forestry activities. In bulk, each class of biomass resource seems great; however, agricultural residues have collection and storage problems, and are seasonal in nature. In addition, the potential of dedicated crops that might support a methanol production industry is not significant. To generate 1,500 tons of feedstock daily (at about 7,000 Btu per pound), the cultivation of about 30 square miles of land would be required, and economics may not permit the dedication of land, water, labor and other resources to biomass production for methanol. However, biomass may emerge as a suitable candidate for supplying regional or local productions of modest scale, particularly in areas where the concentration of biomass residues in centralized facilities already exists. Municipal solid wastes, for example, may well support modest local methanol productions.

This overview has been prepared as a framework for a classification and description of the substantial resources.

C. DESCRIPTIONS AND CLASSIFICATION OF RESOURCES

To assist the processes of resource evaluation, a classification scheme was devised. Potential methanol resources, according to the classification scheme, are identified in Table 3-1. The raw materials identified are the classic feedstocks for methanol production, or are the natural alternatives available in and near the state. All of the selected resources conform to the requirements established in Chapter 3.

Not all the resource statistics are firm data. The fossil hydrocarbon estimates, for example, are subject to resource discovery and increased exploitation efficiencies. Others, like some biomass candidates, are summary estimates of annual yields, and are considered forecasts dependent upon seasons, weather, crop rotation and the marketplace. Some data describing offshore candidates, such as Mexico's natural gas resources, are highly uncertain, and a reasonable estimate has been provided.

The description of potential methanol resources has not addressed economic, transportation and competitive factors. Those influences are studied and reported in other parts of this study.

In classifying the resource spectrum, a major subdivision between the developed and the potential resources seems useful. The developed are those flowing, or available to flow now or in the immediate future. The potential division incorporates the developed, and adds the resources which can be identified but are not yet on-stream. Thereafter, each of the two principal divisions branches to two subclasses, the conventional and the unconventional. These are further divided into California and imported categories.

Table 3-1. POTENTIAL METHANOL RESOURCES FOR CALIFORNIA

	ESTABLISHED RESOURCES			POTENTIAL RESOURCES (INC. ESTABLISHED) (ESTIMATES)	
	PRODUCTION	RESOURCES	RESOURCE Btu QUADS	QUANTITIES	RESOURCE Btu QUADS
CONVENTIONAL RESOURCES					
DOMESTIC					
o Fossil Hydrocarbons					
o Natural Gas, On-shore	337.5 BcfA	3.7 Tcf (1979)	4	8 Tcf	8
o Natural Gas, Off-shore	19 BcfA	NA	NA	NA	NA
o Coal	NIL	90 Mtons	1.6	90 Mtons	1.6
o Crude Oil	314.4 MbblA (1979)	5.0 Bbbl (1979)	30	4 Bbbl	24
o Petroleum Coke (By-product)	12 MbblA	175 Mbbl	0.014	140 Mbbl	1
o Biomass					
o Agricultural Industry Wastes					
Dry Mill Trash & Hulls	888 KtonsA	95 KtonsA	0.014A	100 KtonsA	0.0015A
Vegetable Packing Shed	16 KtonsA	12 KtonsA	0.0002A	15 KtonsA	0.0003A
Food Industry	1,218 KtonsA	791 KtonsA	0.01A	800 KtonsA	0.01A
o Agricultural Field Residues					
High Moisture	1,106 KtonsA	NIL	NIL	NIL	NIL
Low Moisture	5,501 KtonsA	876 KtonsA	0.013A	1,000 KtonsA	0.015A
Vegetable Fields	1,706 KtonsA	NIL	NIL	NIL	NIL
Orchard Pruning	320 KtonsA	98 KtonsA	0.0017A	100 KtonsA	0.0018A
o Dairy Feed Lot & Poultry Wastes	3,553 KtonsA	882 KtonsA	0.012A	1,000 KtonsA	0.013A
o Municipal Solid Wastes	13 MtonsA	5.5 MtonsA	0.05A	6 MtonsA	0.06A
o Forestry Wastes					
Lumber Mill Wastes	4,615 KtonsA	1,555 KtonsA	0.03A	1,200 KtonsA	0.02A
Harvesting Residues	5,086 KtonsA	5,086 KtonsA	0.09A	4,000 KtonsA	0.07A
IMPORTED					
o Fossil Hydrocarbons					
o Natural Gas					
Western States	1.0 TcfA	100 Tcf	100	100+ Tcf	100+
Canada	0.4	33 Tcf	33	100+ Tcf	100+
Mexico	100 BcfA	60 Tcf	60	1,000+ Tcf	1,000+
SNG	NIL	NA	NA	100+ Tcf	100+
LNG, Alaska North Slope	NIL	400 McfD	0.4D	2,500 McfD	0.0025D
Alaska, Cook Inlet	NIL	400 McfD	0.4D	1,000 McfD	0.0010D
Indonesia	NIL	500 McfD	0.5D	1,000 McfD	0.0010D
o Coal, Southwestern States	2.0 MtonsA	631 Btons (1981)	14,000	631 Btons	14,000
Northern Rockies & Plains	NIL	1,400 Btons (1981)	30,800	1,400 Btons	30,800
o Crude Oil, Alaska	271.3 MbblA (1980)	10 Bbbl	16	15 Bbbl	18
Indonesia	72.8 MbblA (1980)	20 Bbbl	32	30 Bbbl	36
Other	15 MbblA	100 Bbbl	160	300 Bbbl	360
UNCONVENTIONAL RESOURCES					
DOMESTIC					
o Fossil Hydrocarbons					
o Petroleum					
Abandoned Reservoir Crude	NIL	66 Bbbl	396	75 Bbbl	450
Heavy Oil in Rock	NIL	1,850 Mbbl	13	4 Bbbl	28
o Kerogen, Kerogen Derivatives	NIL	NIL	NIL	500 Bbbl	2,750
o Dedicated Biomass					
o Forest Cultivation	NIL	NIL	NIL	10 MtonsA	0.0018A
o Crop Cultivation, Terrestrial	NIL	NIL	NIL	15 MtonsA	0.0027A
Marine	NIL	NIL	NIL	1.28 MtonsA	0.000006A
Fresh Water	NIL	NIL	NIL	1.8 MtonsA	0.000009A

UNITS: Prefix: K = Thousand, M = Million, B = Billion, T = Trillion
Root: ton = 2,000 lb., cf = cubic feet, bbl = barrel
Sufix: D = Daily, A = Annually

1. Established and Potential Conventional Resources

a. Domestic Resources (within California)

Natural Gas. The state produces about 20 percent of its natural gas consumption, drawing principally from onshore resources and adding from offshore productions (Figure 3-1). The Oil and Gas Division Supervisor's Report for 1979 records 4.4 trillion cubic feet as the established in-state resource in December 1979. Assuming no additions through discovery, the resource was approximately 3.7 Tcf in 1981.

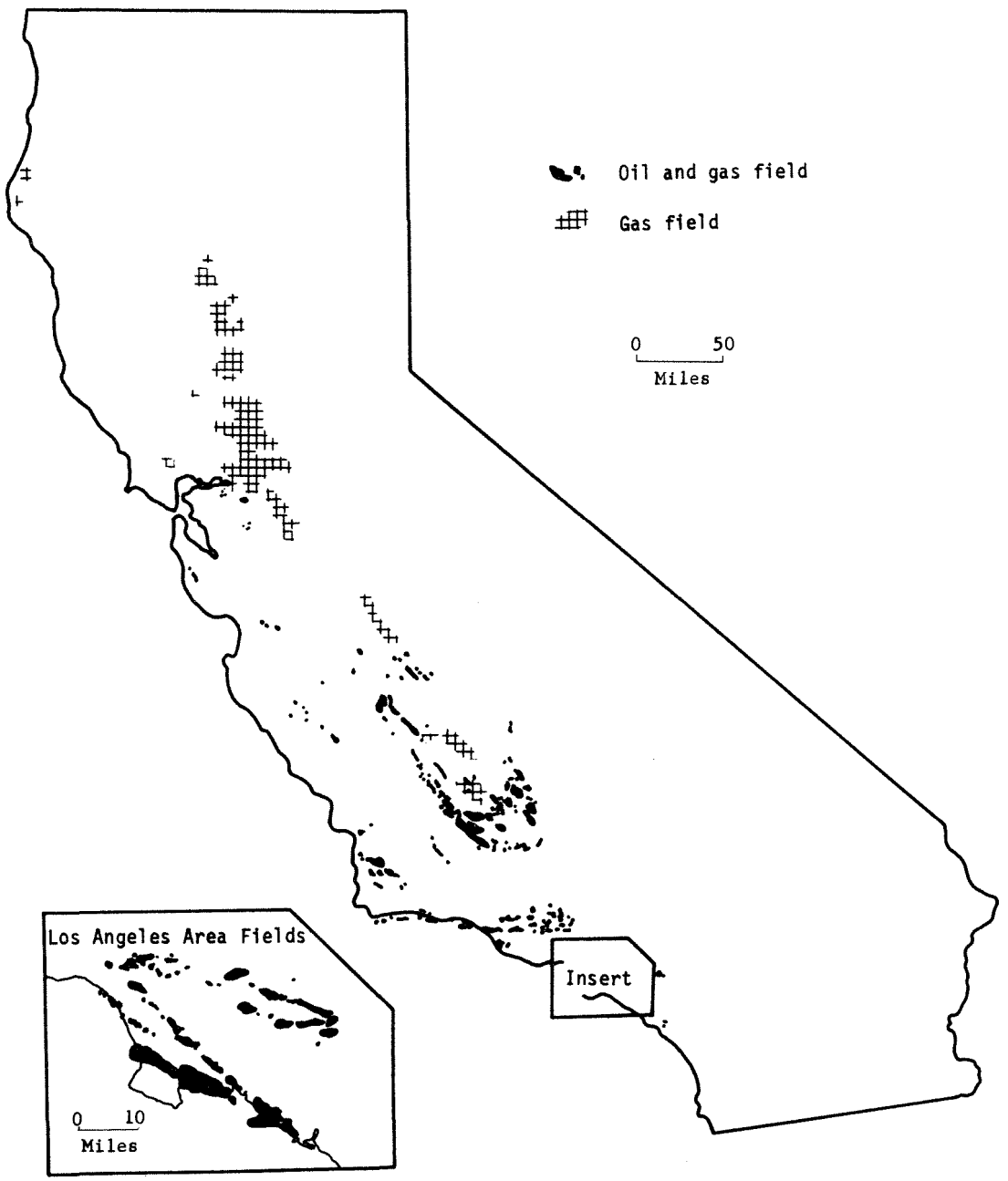
However, it is characteristic of the natural gas production industry that resources are critically influenced by market price, and the state resource at any time should be assessed in consort with the ruling price level. The June 1980 Staff Report (CEC) advises that a doubling of the gas price, for example, would act to expand greatly the volume of established resource. In accord, and judging that price increases will follow deregulation, it seems reasonable to indicate California's potential gas resource at twice its established quantity.

Coal. The state produces no significant quantity of coal. Ninety million tons of lignite are scattered through five counties, mostly in geology discouraging to mining (Figure 3-2).

Petroleum. The state's crude oil production has verged on a million barrels per day since the 1950s. In December 1979, the known recoverable resource remaining was estimated at 5 billion barrels. The principal production locations are Wilmington, Elk Hills, Midway-Sunset, Kern River, Belridge South, San Ardo, and Huntington Beach. Together, these fields produced 63 percent of the state total in 1979.

The state's exploration is considered nearly complete, with the implication that resources will be depleted as production continues. However, a significant residual volume of petroleum lies in all of the reservoirs representing the majority fraction of identified oil that would not respond to conventional drilling techniques. Extraction efficiency in the state has been approximately 25 percent of oil in place. Advanced extraction techniques may increase that efficiency, and methods may be developed to exploit the residuum; thus, the recoverable resource quantity may be significantly increased.

Agricultural Industry Wastes. In 1979, the A. D. Little Company examined California's biomass energy potentials in a study for the California Air Resources Board. Data from the Little study were used in assessing bioenergy resources. Wastes from harvested crop processes and animal dressing are dispersed throughout the state. Generally, they are subject to decay, are diverse in character, and need some intense preparation prior to processing. Overall, they aggregate nearly 900 thousand tons/year, but their potential use in methanol production is discouraged by problems of collection, preservation and storage.



(Source: Ref. 16)

Figure 3-1. CALIFORNIA OIL AND GAS FIELDS

(Source: Ref. 16)

Figure 3-2. CALIFORNIA COAL DEPOSITS

Agricultural Field Residues. Rice stalks, corn stalks and other crop wastes are produced at an annual weight of about 8,600,000 tons. However, high moisture content, contaminants and the dispersed nature of much of this resource suggest that as little as 1,000,000 tons (about 15 TBtu) annually might be usable. These resources, however, are dispersed in location and seasonal in occurrence.

Dairy Feed Lot and Poultry Wastes. As a collected resource, these manures amount to about 3,500,000 tons in California every year. About 47 percent of these wastes is returned to the soil, and 28 percent is marketed for other purposes. A. D. Little's study determined that in only three areas of the state would there be concentrations of industrial significance.

Municipal Solid Wastes. The total annual production of MSW in California approaches 19 million tons. A. D. Little reported that 31 of California's 58 counties each produce less than 200 tons per day. Eight counties with concentrated populations each produce 1500 tons or more daily, and in aggregate, about 13 million tons annually. If 70 percent of that mass were collected, with its 61 percent combustibles (4800 Btu per pound), and were converted in processing with 60 percent efficiency, about 50 trillion Btu would be realized.

Forestry Wastes. Slash, toppings, limbs and brush constitute the work site residues from logging. Sawdust, bark, offcuts, trim and shavings are the wood wastes from milling. The former has traditionally been left to enrich the forest soil; the latter has usually been disposed of in waste burners or boilers. Presently, much of the mill waste is used in particleboard processing.

Approximately 4,615,000 tons/year are wasted in California's forests, and 5,068,000 tons/year in mills. One-third of the forest wastes might be collected and that value salvaged. However, competition exists, and will probably increase, for the milling coproductions.

b. Imported Resources

Natural Gas. California imports gas from the southwestern states, the Rocky Mountain states, Canada and Mexico via pipelines. The resources upon which these supplies depend are indefinite because they expand with discovery and in response to price. Much of the data is proprietary. A California Energy Commission Staff Report (1980) advises that the state's needs can be met for the next 100 years at gas pricing of $3/Mcf (at the time of this study, market price was in the neighborhood ot $2.20/Mcf). Beyond that time frame, an extended supply life will vary with pricing and technology improvements.

The Canadian and Mexican gas resources are not fully explored. For the purposes of this report, we have assumed that the present rate of supply from

Canada to California will be available for the next 80 years. It has also been assumed that Mexico's gas supply to the state will increase from 100 Bcf to 600 Bcf/year and will hold that pattern for 100 years.

Potentially, even more important than the extent of natural gas reserves within the state are remote gas deposits on the Pacific rim which could be converted to methanol and shipped to California ports. There are a number of rationales why such gas could be used as a methanol feedstock and supplied at prices well below that for pipeline gas.

There are a number of developing countries with significant gas resources on the Pacific rim, including Mexico, Indonesia, Colombia, Ecuador, Chile, Peru, Bolivia, China, and Malaysia. In addition, of course, there are significant natural gas reserves in Alaska which should be distinguished between north slope and southern resources. The key to utilizing these resources for methanol production are:

(1) Countries with large gas reserves and small existing and potential domestic gas markets.

(2) Countries with significant gas reserves but without means to establish pipelines and other infrastructure to utilize the gas directly.

(3) Undeveloped countries with need for foreign exchange who will make decisions on whether to sell remote gas to methanol producers or LNG conversion strictly on the basis of greatest return.

The available information on gas reserves, production rates, consumption in these Pacific rim areas is summarized in Table 3-2.

In addition to the reserve base, we have made a quick analysis of what limits exist on methanol production from these gas resources. The first implication of this table is that there are large quantities of natural gas (most of it associated) being reinjected, flared or exported (approximately 1,325 trillion Btu/year, not counting Alaska). For estimating the limits from these sources, it is important to note that we are not predicting in any way that this gas will be or is economically justified to be converted to methanol. The intent is to see how far the resource base in non-pipeline gas could carry the transition to fuel-based methanol in the most optimistic case that methanol is the most attractive option for utilizing these gas reserves. Thus, the intent is to derive physical rather than economic limits on the resource base.

Given these qualifiers, the results on the far right-hand side of Table 3-2 show that there is a significant potential for methanol production from natural gas in the next 15 years. Using the quantity of natural gas currently reinjected or flared in Pacific rim countries (excluding the U.S. and Alaska) would support over 20 full-scale (3,000 tpd) methanol production plants, or about 6.6 billion gallons per year. In addition, the resource base is sufficient to support these plants for their full 20-year lifetime.

Table 3-2. 1981 ESTIMATED GAS RESERVES IN PACIFIC RIM COUNTRIES* (Trillion Btu)

COUNTRY/ AREA	POTENTIAL GAS RESERVES	ANNUAL TOTAL GAS PRODUCTION	% ASSOCIATED GAS	MINIMUM RESERVE LIFE AT CURRENT PRODUCTION	SHARE OF GAS FLARED OR REINJECTED	SHARE OF GAS PRODUCTION CONSUMED	SHARE OF GAS PRODUCTION EXPORTED	LIMITS ON METHANOL PRODUCTION POTENTIAL				
								BASED ON CURRENT REINJECTION RATE		BASED ON RESERVES		
								PLANTS (3000 tpd)	10^6gal/yr	% OF RESERVES	PLANTS	10^6gal/yr
SOUTH AMERICA												
Bolivia	6,300	144	29	44	60	4	36	2.6	858	45	4.3	1,420
Chile	5,250	224	3	23	44	46	10	3.0	986	25	2.0	650
Colombia	5,600	136	51	41	35	65	--	1.4	476	15	1.3	420
Ecuador	5,250	14	86	375	100	--	--	0.4	-	50	4.0	1,310
Peru	1,750	66	97	26	59	41	--	1.2	389	30	0.8	260
SOUTH PACIFIC												
Indonesia	22,400	952	53	24	28	25	47	8.0	2,555	35	11.8	3,920
Malaysia	18,900	122	100	154	86	4	--	3.2	1,049	40	11.5	3,780
MEXICO	80,500	966	78	83	15	85	--	4.4	1,449	7	8.5	2,820
ALASKA												
North Slope	35,400	648	100	55	91	6	3	17.9	5,289	50	26.8	7,938
Cook Inlet	3,785	299	N/A	13	33	28	39	3.0	885	50	2.9	848
TOTALS								45.1	13,936		73.9	23,366

*Resource data taken from Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries. World Bank, April 1982, p. 60

N/A = Not available

Another simple way to bound the potential methanol production limit is to assume that the current proportion of natural gas flared, injected, or exported will diminish over time as internal demands increase. As an example, we have assumed that internal consumption doubles and that the remaining resource is available for export as methanol or LNG. The product limit measured this way is larger; about 44 plants* and over 14 billion gallons of annual production could be sustained for 20 years. Of course, in reality such plants would be built sequentially rather than all at once. Thus, on a resource limit basis there are adequate resources to sustain the building and operation of one 3,000 tpd methanol plant each year for 20 to 40 years and supply them with feedstock in the Pacific rim. The transition period implications of these resource limits are dealt with in Section V of the summary report, entitled "The Transition Period." On the basis of what has been learned, it is clear that low opportunity cost gas could provide sufficient feedstock to begin a methanol transition. On the other hand, there is clearly not sufficient resource to supply a large proportion of the U.S. fuel market. Thus, our evaluation confirms the conventional wisdom that remote gas is a transition fuel for methanol, and it is of sufficient quantity to sustain west coast markets through the remainder of this century at any realistic neat methanol vehicle penetration rate.

Syngas (SNG). SNG, derived from coal and produced at mine mouth or in California from imported resources, offers a very large downstream option for gas supplier and user. The technology of this resource supply is not yet in place.

Liquid Natural Gas (LNG). LNG is an essential resource in the world marketplace, but is not yet available in California because of constraints surrounding delivery arrangements.

Coal. Kaiser Steel Corporation's operation at Fontana, California, imports coking coals from Utah and New Mexico at a rate of about 2 million tons/year. This established traffic draws upon captive mines that are located among resources estimated at 631 billion tons (JPL estimate). About one-half of that resource estimate is considered exploitable with today's mining technology. These coal resources are partly bituminous (typically 24 million Btu per ton) and partly subbituminous (typically 19 million Btu per ton), with sulfur and ash in the low range.

Western coal resources in the states of Arizona, New Mexico, Utah, Colorado, Wyoming and Montana, as well as Alaskan resources may constitute a vast potential feedstock for methanol production. A recent JPL/University of Kentucky study has indicated that the Rocky Mountain Province may have over 2000 billion tons of coal reserves. Table 3-3 illustrates the characteristics of these reserves.

* If Alaska's south slope resources are added at 50 percent dedication to methanol, three plants and 800 million gallons annually could be added, and the north slope has the potential for 8 billion gallons per year if 50 percent of the resource base were converted to methanol.

Table 3-3. ROCKY MOUNTAIN PROVINCE COALS*

1) Remaining resources in beds not faulted or intruded and dipping less than 15 degrees, by depth of cover:

0-500 ft.	500-2000 ft.	2000-4000 ft.	4000 ft.	Total
190	428	630	832	2080

2) Remaining resources under 2000 feet of cover, by seam thickness:

50 ft.	50-15 ft.	15'-42"	42"-28"	28"-14"	Total
19	81	375	72	71	618

*All figures in billions of tons.

This report concentrates on seven coal regions containing significant resources that could support potential methanol production for California (Figure 3-3). These regions are:

(1) Arizona (Black Mesa)

(2) Southern Utah (Kaiparowits, Kolob-Alton, Henry Mountains)

(3) New Mexico-Colorado (San Juan)

(4) Central Utal-Colorado (Piceance, Uinta, Wasatch, Emery)

(5) Wyoming-Colorado (Green River, Yampa)

(6) Wyoming-Montana (Powder River Basin)

(7) Alaska (Beluga, Susitna, Kenai)

The characteristics of these individual regions, including potential constraints on resource availability, are discussed below. Potential coal resources and coal quality data for the six regions, compiled for the JPL coal resources study, are summarized in Table 3-4.

Arizona (Black Mesa). According to the 1981 Keystone Coal Industry Manual, the Black Mesa area has 2100 million tons of reserves, mostly 0-1700 feet from the surface. Strippable reserves are estimated to be 980 million tons, mostly within 0-130 feet of the surface. The coal resources study by JPL/University of Kentucky has indicated that the Black Mesa region may have a potential 50 billion tons of resources buried under less than 2000 feet of cover. Most of the coal seams are 42-inches to 15-feet thick.

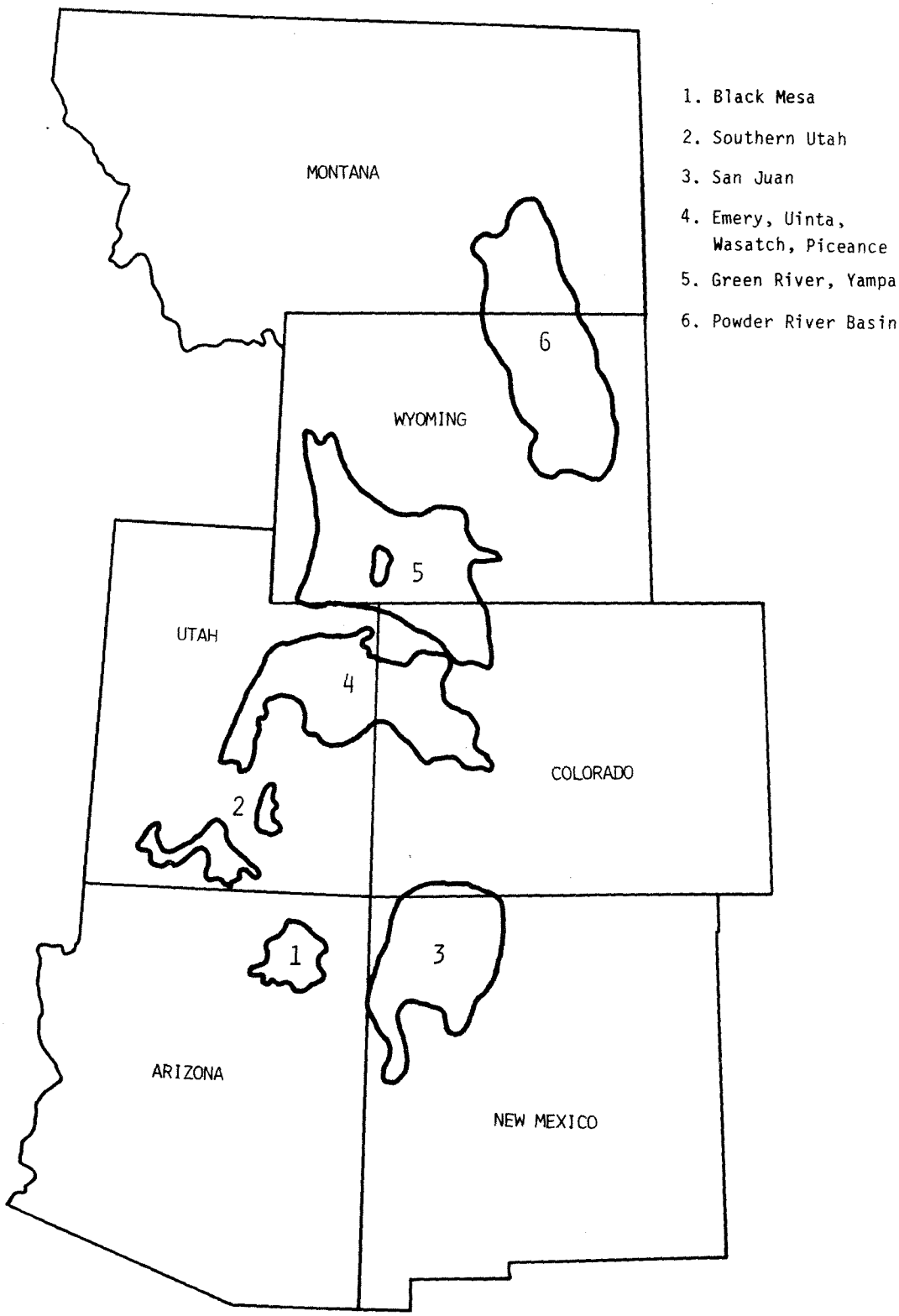


Figure 3-3. SELECTED WESTERN COAL REGIONS

Table 3-4. COAL RESOURCE DATA

	COAL REGION	TOTAL TONNAGE*	TONNAGE BY DEGREE OF DIP*		TONNAGE BY OVERBURDEN THICKNESS*			TONNAGE BY SEAM THICKNESS* (<2000' OVERBURDEN)				AREA OF RESOURCE ESTIMATE	COAL QUALITY			
			< 15°	> 15°	0-500'	500-2000'	>2000'	>15'	15'-42"	42"-28"	18"-14"	(sq. mi.)	SULFUR(%)	ASH(%)	BTU	RANK
1	Black Mesa	51.6	51.6		22.2	29.4	-		45.1	2.8	3.7	4,023	.5-2.2	3.4-50.8	5,119-12,060	SUBBIT
2	Kaiparowits	44.2	41.6	2.6	20.3	11.1	12.8	5.2	19.8	3.3	3.1	1,071	.68-.88	7.0-11.1	9,309-11,210	BIT
	Henry Mountains	1.4	1.4		0.2	0.8	0.4		0.7		0.3	189	.87-1.8	9.5-10.7	11,000-11,253	BIT
	Kolob-Alton	15.1	15.1		2.0	4.7	8.4	0.7	5.5	0.1	0.5	910	.64-5.8	7.7-13.6	7,935-10,492	BIT
3	San Juan	179.8	162.6	17.2	69.5	43.3	67.0	1.1	70.2	16.6	24.9	10,248	.6-.86	15.0-20.4	8,900-10,200	SUBBIT
4	Emery	18.1	18.1		0.7	2.0	15.4		2.2	0.4	0.1	1,036	.39-5.5	5.5-13.8	11,400-14,380	BIT
	Wasatch	95.8	94.7	1.1	10.1	13.0	72.7	3.7	15.1	2.7	1.6	5,307	.49-1.09	6.1-7.0	11,727-12,825	BIT
	Uinta	20.0	18.1	1.9	1.8	3.9	14.3		4.5	0.6	0.6	3,562	.8-2.1	6.4-13.3	10,690-12,200	BIT
	Piceance	201.4	182.6	18.8	29.8	24.3	147.3	11.4	25.9	8.1	8.7	7,665	.4-1.9	3.2-9.2	11,040-14,170	BIT
5	Green River, Yampa	806.3	787.5	18.8	27.1	96.3	682.9	3.2	83.4	19.7	17.1	11,778	.42-5.4	2.2-15.3	7,980-12,447	SUBBIT
6	Powder River	570.1	566.4	3.7	36.6	176.5	357.0	77.0	107.6	18.6	9.9	16,271	.34-1.5	4.3-11.4	7,884-9,710	SUBBIT

*Billions of Tons

The Black Mesa coal region is totally within the jurisdiction of the Navajo and Hopi tribes. Currently, Peabody Coal has lease agreements with the Indians for 64,858 acres. Peabody operates two coal mines in the Black Mesa area; almost all of the coal produced is supplied to electric power generating plants under long-term contracts. Coal from the Kayenta Mine is shipped via electric rail to the Navajo generating plant in Page, Arizona. Coal from the Black Mesa mine is transported via slurry pipeline to the Mohave generating plant in Nevada. Coal from these two mines has approximately 10,700-10,800 Btu/lb, 4.3 percent ash, and 0.46-0.49 percent sulfur.

The possibility exists of a third mine opening in the Black Mesa region, making more coal available in the near future; however, final say on exploitation of coal resources in this area rests with the Navajo and Hopi tribes. Coal transportation from this region is only via private rail and slurry pipeline.

Southern Utah (Kaiparowits, Kolob-Alton, Henry Mountains). These coal fields have bituminous coal resources, somewhat higher in sulfur than most western coals, that are largely undeveloped. The JPL/University of Kentucky study indicates that there may be approximately 60.7 billion tons of resources in these coal fields. The largest coal field, the Kaiparowits, may have over 30 billion tons of potential resources with relatively low sulfur and ash contents; the Henry Mountains field has about 1.4 billion tons of potential resources of similar quality. The Kolob-Alton fields have about 15 billion tons of coal that are relatively high in sulfur and ash. Data from the JPL study for these coal fields are summarized in Table 3-4.

The Kaiparowits coal field, which is currently undeveloped, contains over 30 percent of Utah's coal resources. The JPL study indicates that there are about 44.2 million tons of resources in this field; the U.S. Geological Survey has estimated that there is a potential 30 billion tons. Some of the utility-owned coal reserves in this area, originally intended for the cancelled Kaiparowits power plant, may be used in a planned coal gasification project. In addition, a 400 MW power plant may be planned for the area.

In the Kolob-Alton fields, there are no mines currently operating. Keystone estimates that the Alton coal field may have 200-400 million tons of strippable reserves. Much of the Alton coal is under less than 60 feet of overburden, much of which is soft and will not need to be blasted. Over 28,000 acres with coal rights are currently held as federal leases by Utah International and Nevada Power. In addition, a planned power plant near St. George, Utah, will probably use coal resources from this area. The Kolob coal field has coal that is of relatively poor quality (high ash and sulfur contents).

According to the JPL study, the Henry Mountains coal field has a potential 1.4 billion tons of reserves. Keystone estimates that the area has 340 million tons of coal in place at depths of 1400 feet or less, in beds more than 4-feet thick. Most of the valuable coal land in this area is held by Amax Coal Co., but there are currently no operating mines in the Henry Mountains field. Plans for the Intermountain Power Project may involve use of Henry Mountains coal.

These coal fields are located mainly on federal and state land. Several environmentally sensitive areas (Zion National Park, Cedar Breaks National Monument, Bryce Canyon National Park, and Capitol Reef National Monument) are in the region and may impede development of these coal fields. Other constraints on development include remoteness, rugged topography, and lack of railroad spurs.

New Mexico-Colorado (San Juan). The San Juan coal basin in northwestern New Mexico and southern Colorado contains a potential 180 billion tons of resources, according to the JPL study. Over one-half of this tonnage is in seams 42-inches to 15-feet thick, and under less than 2000 feet of overburden. These subbituminous coals are low in sulfur, but moisture and ash vary widely. Characteristics of the San Juan coals as defined by the JPL study are shown in Table 3-4.

According to Keystone, the San Juan Basin contains 6.5 billion tons of strippable reserves. Companies owning reserves in the San Juan area include Utah International, Consol, El Paso Natural Gas Co., Pittsburgh & Midway, and others. The best-known and best-developed coal field within the San Juan Basin is the Navajo Field, within the Navajo Indian reservation. Coal mined from Utah International's Navajo and San Juan mines, which ranges from 8600-9200 Btu/lb, is all committed to the Four Corners utility and transported there via a short railroad line that runs from the mine to the utility.

Much of the land in this area is owed by Indian tribes. The rest is owned by the federal government, the state, railroads, and other private industries. Access by rail is currently a problem for many of the coal regions within the San Juan Basin; new railroad spurs are needed for other markets.

Central Utah-Colorado (Emery, Wasatch, Uinta, Piceance). This area has predominantly bituminous, low-sulfur coals, with high heating values (11,000 - 14,380 Btu/lb). According to the JPL study, this area has a potential resource total of 335.3 billion tons; about 62.8 billion tons are in seams thicker than 42 inches, under less than 2000 feet of overburden. The Emery field is the smallest, with potential resources of 20 billion tons. The Wasatch field, adjoining the Emery field to the north, has a larger amount of resources characterized by much greater coal thicknesses (some resources occur in beds thicker than 15 feet). The Uinta Basin has coals of similar quality, but the total coal thickness is substantially less. The Piceance Basin directly to the east of the Uinta Basin has large amounts of coal resources mostly concentrated in seams thicker than 42 inches. A large proportion of the coal in these four areas occurs at depths greater than 2000 feet. The characteristics of these coals as defined in the JPL study as shown in Table 3-4.

According to Keystone (1981), the small Emery field has 630-900 million tons of coal considered recoverable; 140 million tons of this coal may be recovered by surface mining. This field may eventually supply coal for the Intermountain Power Project (planned to be on-line by 1986), but no railroad

serves the field at present. The Wasatch area, with 14 currently active mines, has a potential resource of 10.2 billion tons in seams greater than 4-feet thick, under 3000 feet or less of overburden. The JPL estimates are much higher. Constraints on mining this resource include thick overburden, faulting, and water problems. Presently, the northern part of the Wasatch area is served by three rail spur lines; southern area producers must truck coal. The Piceance and Uinta areas together have large amounts of resources; much of the coal currently mined is coking coals from underground mines.

Lands in this area underlain by coal are mainly federal, state, and privately owned. The Uinta-Piceance areas also have vast oil shale resources on federal lands, and potential conflicts may arise concerning leasing for coal/oil shale resource extraction. Competition for scarce water supplies may also be a constraint. In addition, many coal resources in this area are high-quality or coking-quality coals, deeply buried and faulted. Transportation problems exist in this region, because many areas are not served by rail spurs, and much of the existing trackage is not adequate for heavy unit trains.

Wyoming-Colorado (Green River, Yampa). According to the JPL study, the Green River Basin of southwestern Wyoming and northwestern Colorado has a potential 800 billion tons of reserves of mostly subbituminous coals, ranging from 8000-12,000 Btu/lb, with ash and sulfur percentages similar to other Central Rocky Mountain Province coals. Most of the coal is in seams greater than 42-inches thick, but much of the resource is buried under more than 4000 feet of overburden. Characteristics of the Green River Basin coals, from the JPL study, are given in Table 3-4.

Keystone (1981) and the U.S. Bureau of Mines estimates that there may be 2.9-3.6 billion tons of strippable coal in the Green River Basin area of Wyoming and Colorado. Presently, about 37 percent of Colorado and Wyoming's coal production comes from this area. There are 20 active mines in this area; 15 percent of them are surface mines, which produce 98 percent of the region's coal. Most of the coal is used for electric power generation in Colorado, Wyoming and other states.

Most of the land in this area is federal land, administered by the Bureau of Land Management and the U.S. Forest Service. Parcels of state and private land occur within the federal land. Some of the coal areas are located near Rocky Mountain National Park and other wilderness areas, preservation areas, national wildlife refuges, national monuments, and state recreation areas and parks. Large areas of strippable coal deposits are located near existing railroad facilities.

Montana-Wyoming (Powder River Basin). The Powder River Basin contains 30 percent of the resources of the entire Rocky Mountain Province. The JPL coal resources study indicates that the area may have as much as 570 billion tons of coal resources. About 40 percent of these resources lie within 2000 feet of the surface; one-third are in seams greater than 15-feet thick. Powder River Basin coals generally have low ash and sulfur contents. Table 3-4 presents JPL study results on the Powder River coals.

According to Keystone (1981), the Powder River Basin has nearly 23 billion tons of strippable reserves. The U.S. Bureau of Mines estimates that there are about 31 billion tons of strippable reserves; individual state estimates are as high as 47 billion tons. The area is known for strippable "superbeds" of coals 50- to 250-feet thick under less than 300 feet of overburden. Most of the current and planned activity in the Powder River Basin is in the northern and eastern parts. Many private companies and utilities operate strip mines and own reserves in the Powder River Basin. The coal is primarily used for electric power generation in Wyoming, Montana, and about a dozen midwestern power plants.

The federal government administers about 25 percent of the land in the Powder River Basin; of this land, one-quarter is owned by Indian tribes. Six percent of the land is state-owned and the remainder is private land.

Many strippable deposits are located near existing rail facilities with access to the Pacific Northwest and the Midwest, but the area is somewhat remote from California.

Reclamation. A major potential constraint on exploitation of all the western coal fields is the requirement for reclamation of surface-mined land. Most state laws require that the land must at least be reclaimed to a condition capable of supporting its existing use prior to mining. Reclamation activities are monitored by the states and the U.S. Office of Surface Mining (OSM) in the Department of the Interior; reclamation on Indian lands is under the jurisdiction of the OSM and the individual Indian tribes.

Returning the land to its previous use is difficult in the semiarid and arid West. Land uses in the Rocky Mountain Province coal-bearing areas include cattle and sheep ranching, dryland farming, some irrigated farming, and forestry, depending on elevation and rainfall. Large tracts are covered by vegetation communities including sagebrush scrub, prairie and grassland, and pine forest. In some areas, irrigation may be necessary during the first year of reclamation to revegetate surface-mined areas with vegetation comparable to what existed prior to mining. Some areas of higher elevation, such as Black Mesa in Arizona, may not need irrigation for reclamation. Some of the strippable areas in the Green River and Powder River Basins may also have sufficient rainfall to ensure reclamation success. Both surface and ground water resources need to be evaluated in the water-scarce areas before mining is planned.

The generally poor soils of the Rocky Mountain Province tend to compound reclamation and revegetation problems. Soil horizons are poorly developed, humus content is low, and sufficient topsoil for revegetation is often absent. Erosion rates tend to be high.

Reclamation costs in the Rocky Mountain Province coal-bearing areas average about $3000/acre. Areas with poorer soils and extremely low rainfall may have much higher reclamation costs, or reclamation may not be possible at all.

Alaska (Beluga). According to a recent study* of the Department of Natural Resources, the State of Alaska has coal resources of 1.4 billion short tons of "measured" resources, 110.7 billion short tons of "indicated and inferred" resources, and "hypothetical" resources of 1774 billion short tons. A large proportion of these resources are located in northern Alaska in the NPRA. In the southern area, the coal fields around Cook Inlet (Beluga, Susitna, Kenai) are particularly interesting as potential sources of coal for methanol conversion to California. The coals in these fields are mostly subbituminous with approximately 9500 Btu/pound. In addition, they are mostly low-sulfur coals which can be surfaced mined.

The state of Alaska estimates that "indicated and inferred resources" in the Beluga, Kenai and Susitna fields at about 10.5 billion short tons. Since a 5000 ton-per-day methanol plant would require about 6 million tons per year of feedstock, there is ample coal in the Cook Inlet region to support a number of methanol conversion plants. Much of this coal is located within 25 miles of the coast, which would reduce transportation cost by rail to terminal facilities for shipment to California by tanker.

In northern Alaska, the resource base is much larger with a much higher proportion of bituminous coals. The "measured" resources alone in this area are nearly 500 million tons, while the "indicated and referred" resources are over 200 billion tons. Thus, the Alaska resource is very large compared to near-term and mid-term demand for methanol which could utilize this feedstock. In the near-term, the most likely area for development is the Beluga field which, with low opportunity cost for the coal, the potential for inexpensive tanker transport for methanol, and possible SFC support, is the most likely coal-to-methanol concept which would affect California methanol markets directly.

Crude Oil. The state currently imports by tanker vessel about 270 million barrels of crude from Alaska's North Slope production via Valdez. A fraction of the state's annual crude stocks comes from Indonesia, whose sweet crude goes to specialty products. Other imports represent transfers, mostly from the Gulf Coast, to balance product streams.

2. Established and Potential Unconventional Resources

a. Abandoned Reservoir Crude. About 66 billion barrels of crude oil unavailable for extraction by conventional technology exist in California's reservoirs. This figure represents that component of the original resource which would not respond to conventional drilling techniques. Its volume approaches 74 percent of the original, in-place resource measurement, or about thrice the total volume produced. This very large potential resource may become exploitable by advanced procedures. Presently, this resource is unconventional, but known and measured.

* McGee, D. L., and Emmel, K. S., Alaska Coal Resources, State of Alaska, Alaska Department of Natural Resources, April 1979.

b. Heavy Oil in Rock. Widely scattered in California, mostly in the coast ranges, is a series of rock occurrences bearing concentrations of heavy oil fractions. These appear to be exposed reservoir members from which the volatile hydrocarbons have fled. Several outcrops are very extensive. A few have been investigated, while others are not well known. The McKittrick diatomite, for example, in its exposure along the Kern River, is well explored where it outcrops updip from a major heavy oil reservoir. This singular occurrence offers a mineable hydrocarbon resource with recoverable crude estimated at 800 million barrels. Other significant oil-rock resources occur at Santa Susanna, Edna, San Ardo, Casmalia and Point Arena. Established reserves are estimated at 1,850 million barrels; potential reserves are estimated at 4,000 million barrels.

These resources appear amenable to surface mining techniques. Processing to extract crude may tend to be resource-specific, as this genre of oil host rock exhibits varying characteristics; some may present separation difficulty.

c. Kerogen and Kerogen Derivatives. Exploitation of the extensive kerogen-rich marlstones of the Piceance Basin in northwestern Colorado and those of the Unita Basin in northeastern Utah has been sought and planned since the 1920s. Development of this resource potential now appears imminent, and pilot mining and processing programs are in progress. Large-scale production is still to be realized, and until such facilities are on-stream, California can only consider kerogen or its syncrude as another potential resource.

The order of that potential is between 400 and 600 billion barrels in place as a national resource based upon criteria of formations at least 15-feet thick and containing at least 25 gallons of kerogen per ton. Exploitation by conventional mining practices would degrade that potential seriously. Unconventional procedures are being tested.

With few exceptions, development activities in the "oil shale" basins are being conducted by the major U.S. petroleum producing corporations.

d. Biomass. Unconventional biomass resources are those of more or less ordinary character cultivated and dedicted to unconventional purposes, in this case methanol feedstock probably derived by pyrolysis or anaerobic activity. Several potential resources are sugar cane, short rotation tree crops, eucalyptus, desert plants, and marine kelp. In some circumstances, one or more of these potential resources may merit in-depth investigation, but land, irrigation, and preprocess handling requirements may discourage first-place consideration.

D. CONCLUSIONS

California offers a varied, favorably distributed and generous selection of raw material candidates for methanol production. There are choices avail-

able between domestic and imported, plant and mineral, and dedicated and co-product supplies.

As would be expected, the flow crossroads of the imported raw materials tend to coincide with the population centers. The agricultural and silvicultural resources tend to cluster in areas which are less well served by transportation networks.

The diversity of the potential raw material supplies for a methanol industry dedicated to California's fuel needs makes production location a component of the industrial decisions to be studied. The potential long-term and reliable raw material candidates lie out of state. Some are currently being imported; others may be available for import to the state. The domestic resources are either short lived or less consistent in makeup than are the coal, gas and petroleum supplies situated outside California. Methanol production from coal or natural gas at the source, or en route to California for transport to the state, emerges as the most promising methanol alternative from the perspective of potential exploitable resources.

E. REFERENCES

1. 65th Annual Report of State Oil and Gas Supervisor, PRO6, California Division of Oil and Gas, 1979.

2. California Energy Commission, Fuel Price and Supply Projections: 1980-2000, Staff Report, June 1980.

3. Hallmark, F.O., Unconventional Petroleum Resources in California, Div. O&G, TR25.

4. "Petro Mine," Engineering and Mining Journal, McGraw-Hill, N.Y., June 1981.

5. A. D. Little, Inc., California Clean Fuels Study, ERC&DC, Air Resources Board, Cambridge, Mass., April 1978.

6. Rubin, B., Bord, U. Y., and Ramsey, W. J., An Assessment of the Potential for Using Alaskan Coal in California, LLL. UCRL-52511, June 1978.

7. TEKNEKRON, Municipal Solid Wastes and Agricultural Residues vs. Coal as an Energy Feedstock, Berkeley, Calif., March 1977.

8. California Energy Commission, Renewables and Alternative Technologies Symposium, Staff Draft Report, September 1980.

9. Arthur Young and Co., Analysis of Financial Incentives for Biomass Energy, Sacramento, Calif., January 1981.

10. Hildebrand, R. T., "Coal Deposits in California, a Selected Annotated Bibliography," California Geology, USGS, Denver, Colo., December 1978.

11. Noyes Data Corp. Methanol Technology and Application in Motor Fuels, Park Ridge, New Jersey, 1978.

12. California Energy Commission, Quarterly Fuel and Energy Summary, Vol. 6, No. 4, Fourth Quarter, 1980.

13. Characterization of Seven United States Coal Regions, DOE/ET/10023-2, U.S. Department of Energy, February 1981.

14. Ferm, J. C., and Muthig, P. J., A Study of the United States Coal Resources, JPL Publication 81-XX, December 1981.

15. 1981 Keystone Coal Industry Manual, McGraw-Hill, 1981.

16. Atlas of California, Academic Book Center, Portland, Oregon, 1979.

CHAPTER FOUR

METHANOL AND OTHER SYNFUELS: PRODUCTION OPTIONS AND COSTS*

A. INTRODUCTION

In this chapter, an attempt is made to characterize the pertinent process technologies, calculate production costs, perform sensitivities, and compare the alternatives for methanol and other synfuels. It is important to acknowledge that the cost estimates used in this chapter are based on existing published sources; JPL has not performed any detailed engineering cost estimates for the study. For methanol production alternatives, we have compiled a fairly comprehensive set of recent estimates, compared them, attempted to resolve inconsistencies through discussions with some of the project sponsors, and presented our findings based on a consistent set of financial and technical parameters. For competing synfuel alternatives, we have not made as detailed an evaluation, but we have taken public documents and imposed a consistent set of financial parameters as in our methanol production cost analysis. Given the tremendous uncertainties involved in the estimation of costs for these large-scale projects, it is important to maintain the perspective that point estimates of cost for any plant which is undemonstrated commercially are unreliable. In this report an attempt has been made to apply contingencies of appropriate levels to technologies at different stages of development to help generate more meaningful estimates. We have also performed numerous cost sensitivities to important cost drivers to generate a range of product costs associated with alternative systems. More important, however, than these these mechanical procedures, we have based our conclusions on the premise that absolute decisions cannot be made on the basis of small differences in estimated production costs for alternative synfuels at this point in time. As a result of our evaluation, however, we do feel that some options tend to dominate others under any reasonable set of assumptions. Thus, firm conclusions can be drawn about a few of the relative options and they will be identified and discussed.

The organization of this section of the report is to identify and characterize the alternative methanol production technologies, discuss their status, and project their investment and operating costs. A similar analysis is then done for the competing synfuels which would be alternatives to methanol in various applications. Finally, an evaluation is performed of the production economics of all the options on a consistent basis, and sensitivities are performed.

B. METHANOL PRODUCTION TECHNOLOGIES

The production technologies of relevance to methanol production for California applications are influenced by the resource base which would supply feedstocks. In our analysis we have considered Western coal, Alaskan coal,

* All cost or price figures in this or subsequent chapters are in 1981 dollars unless explicitly stated otherwise.

remote natural gas, petroleum coke, and biomass as potential feedstocks.* Each of these options is discussed below.

1. Western Coal-to-Methanol Plants

The basic process for converting coal to methanol is to gasify the coal, producing a synthesis gas which is then synthesized into methanol through different processes. The existing (first generation) technologies to perform this gasification process are the the Lurgi Dry Bottom, Winkler, and Koppers-Totzek technologies. Of these, the Lurgi Dry Bottom is probably the most thoroughly commercially proven approach. For methanol synthesis there are two commercial technologies: ICI and Lurgi. Major improvements in gasification technology are under development including the following technologies: Texaco Partial Oxidation, Shell Koppers Entrained Bed, Lurgi moving bed slagging gasifier and the Winkler fluidized bed gasifier.

a. Capital Cost Overview. In examining coal-to-methanol production costs, we attempted to obtain sufficient recent estimates so that the various sources could be checked against one another. Three basic sources of data were evaluated: (1) plant cost estimates provided to JPL by sponsors of the study,** (2) published cost estimates funded by the Department of Energy,*** and (3) cost estimates on plant concepts which are currently in the planning stages by companies other than sponsors of this study.**** These estimates are shown in Table 4-1, where adjustments have already been made to put all dollar values in 1981 terms, place contingencies on a consistent (15%) basis, use a plant utilization factor of 90 percent, and combine account

---

* See Chapter 3 for a detailed discussion.

** Estimates were obtained from three of the energy production companies involved in our study. This data is not public information and we cannot cite the specific sources, except to indicate that the plant cost estimate used for the basic reference case (Texaco Partial Oxidation gasification technology for 5000 tons-per-day of methanol output in 1992) is JPL's synthesis of these three industry sources.

*** Recently, Oak Ridge National Laboratory has completed work on a two-phase study for the Department of Energy: Phase I, "Indirect Liquefaction of Coal-To-Methanol and Gasoline Using Available Technology" and Phase II (available only in draft form) "Indirect Liquefaction of Coal-To-Gasoline Using Texaco and Koppers-Totzek Gasifiers." These two in-depth studies were used to check the accuracy of our industry estimates.

**** Two other estimates were obtained on actual projects which are in the planning stages for near-term construction and implementation. The first project was a detailed cost estimate of the Hampshire project published in Synfuels on September 24, 1982. The second project involves an industry source not among this study's sponsors which asked not to be identified in the report, thus we have made some slight modifications to the project scale and description, but have retained the basic information content of the cost estimate.

Table 4-1. CAPITAL COST ESTIMATES: COAL TO METHANOL (millions 1981$)

	PLANT COST ESTIMATES					
SOURCE:	JPL[a]	JPL[b]	JPL[c]	ORNL[d]	ORNL[d]	HAMPSHIRE[e]
GASIFICATION TECHNOLOGY:	TCGP	Lurgi	Winkler	Lurgi	Lurgi	Lurgi
COAL SOURCE:	West	West	Alaska	East	East	West
PLANT SITE:	Minemouth	Developed	Minemouth	Developed	Developed	Minemouth
OUTPUT: MeOH (10^6 gal/yr)	498	242	746	693	1091	-
SNG (10^9 Btu/day)	-	59	-	145	37	-
GASOLINE (10^6 gal/yr)	-	-	-	-	-	277
DIRECT FIELD COST						
Coal Preparation	$62	$57	$142	$152	$159	$65
Air Separation	145	71	121	113	174	163
Gasification	268	105	226	139	139	206
Gas Processing	63	20	29	48	52	62
Acid Gas Removal	114	55	74	92	117	96
Gas Separation	-	46	-	53	31	-
Methanol Synthesis	92	71	140	150	206	77
Reforming & Compression	-	38	49	-	12	-
Emission Control	62	24	15	79	88	61
Steam & Power	150	175	205	252	264	61
Product Storage	24	17	24	28	56	32
Utilities	66	102	110	162	168	109
Offsites	145	85	488	99	113	255
CO_2 Drying & Compression	43	34	-	-	-	-
Methanol Conversion	-	-	-	-	-	79
Purge Gas Methanation	-	-	-	29	8	1
Contingency	*	*	243	306	349	*
SUBTOTAL	$1191	$900	$1906	$1702	$1936	$1221
INDIRECT FIELD COST	-	-	-	629	714	270
Workcamp	-	-	108	**	**	90
Engineering	119	106	144	**	**	207
Owner Admin. & Engr.	39	35	-	**	**	213
TOTAL INSTALLED PLANT	$1349	$1041	$2158	$2331	$2650	$2001
INDIRECT CAPITAL COST						
Start-up & Training	101	38	131	122	138	74
Land	3	2	3	-	-	-
Working Capital	68	56	121	130	143	19
Paid-up Royalties	7	6	10	13	29	***
Initial Catalysts & Chem.	7	6	20	**	**	***
TOTAL CAPITAL REQUIREMENT	$1535	$1149	$2443	$2596	$2960	$2094

a Derived from data obtained from this study's sponsors.
b Derived from data obtained from this study's sponsors.
c Derived from data obtained from Placer Amex.
d Derived from data contained in Liquefaction Technology Assessment - Phase 1: Indirect Liquefaction of Coal-to-Methanol and Gasoline Using Available Technology, Oak Ridge National Lab, ORNL-5664, February 1981.
e Synfuels, "Hampshire Projects 7.8 percent Real Return on Syn-Gasoline Project," September 24, 1982, p 3.

*Contingency included in direct field cost subsystems.
**No breakdown of indirect field cost available.
***No cost given for these categories. As an estimate paid-up royalties and initial catalysts and chemicals would be approximately $8 million each.

categories into a consistent framework. In spite of the above adjustments, the basic data in Table 4-1 are not readily comparable. Differences exist between the estimates resulting from differences in process technology, plant location, coal characteristics, plant scale and product slate. In addition, there are some differences in procedures in the basic cost estimates for identifying the allocation of direct versus indirect field costs. We have not attempted to correct for any changes in this latter type of costing procedure. As a result, the comparison which we will make is at the total capital requirement level, which subsumes these allocation problems between direct and indirect costs.

In order to make meaningful comparisons between these plant estimates, corrections must be made for plant scale, plant location and output slate. These factors are important influences on plant capital cost. First, with regard to scaling we have analyzed in Sections B.1.c and E.3 various factors to be considered in scaling-up coal-to-methanol plants. Our judgement is that a conservative scaling factor would be 0.65 up to 4000 tons-per-day (tpd) and then 0.83 for plants larger than 4000 tpd. Thus, in Table 4-2 we have used these values for adjusting plant scales. A second adjustment was made for the site of the plant construction. In discussions with Chevron, Conoco, ARCO and Fluor, it was suggested that in the absence of a plant designed and costed for a specific site, it is essential to at least correct for cost differences using "location factors" which represent a broad adjustment for the difficulty of building plants in more remote locations. Although the specific location factors of the companies cited based on their own experience varied somewhat, a representative set of factors is shown in Section B.1.c of this chapter. Using these location factors, we have adjusted Eastern (Illinois) sites to western (mine-mouth) sites using a 14.3 percent increase and would expect a Cook Inlet site to be approximately 16.7 percent higher than a Western mine-mouth site. Obviously, the site conditions at an actual plant site would affect these figures considerably, but actual experience has shown that these adjustments are reasonable averages for the locations in question. Finally, some adjustment must be made to the product outputs of the estimates in Table 4-1 to normalize for the mix of products produced. This normalization has been done by taking the relative values of the products in question and converting into "methanol value" equivalent. For example, some of the plants in question produce significant quantities of SNG and LPG along with either methanol or gasoline. Since energy content does not adequately represent* the

Table 4-2. RELATIVE WHOLESALE PRODUCT VALUES IN 1992 TO WHOLESALE GASOLINE (1981$/$10^6$Btu)

GASOLINE	1.00
METHANOL	1.15
SNG	.59
LPG	.59

* In the case where a plant produces both gasoline and SNG, for example, the mix of these two products significantly affect the value of the output since the plant-gate price of SNG is forecast to be only 59 percent of the wholesale gasoline price in 1990.

output of a plant with joint products, a gasoline-equivalent value has been computed. Consistent with the DRI forecast for 1992, the following relative plant-gate values in Table 4-2 have been used for product normalization. This particular normalization is for use of methanol as a transportation fuel in an optimized neat methanol vehicle (which may achieve a 15% efficiency gain over gasoline on a Btu basis). Clearly, if methanol were considered as a utility fuel the relative price corresponding to distillate or residual oil would be appropriate. In this case the main function is to achieve consistency, which makes this choice somewhat arbitrary.

The results of these attempts at making a consistent comparison are shown in Table 4-3 on the basis of the total capital requirement in 1981 dollars per annual gallon of methanol capacity. In the first row of the table there are no area or scale adjustments, thus only the product outputs have been normalized according to the relative values in Table 4-2.

The differences in total capital requirements per annual gallon of methanol capacity appear fairly significant in the baseline case, ranging from $3.27 for the Winkler plant in Alaska to $2.32/annual gallon for the Lurgi plant in southern Illinois. The JPL baseline case for the TCGP process at a Western mine-mouth site is $3.09 per annual gallon at a plant scale of 5000 tons-per-day or 498 million gallons-per-year. The methanol plants not cost-estimated at Western mine-mouth sites in the baseline case are adjusted in the second row of Table 4-3 using the independently derived area adjustment factors in Section B.1.c of this chapter. The net effect of this change is to raise the estimated cost of all non-mine-mouth plants approximately 14 percent to account for the difficulty of moving men and machinery to remote sites, loss of labor productivity in difficult environments, and added infrastructure costs in relatively undeveloped locations.

In the third row of Table 4-3 an adjustment is made for scale differences in the alternative plants. A scaling factor of 0.83 was used to bring the capacity of all the plants to 996 million gallons-per-year of methanol.* This scale factor was independently obtained from estimates supplied to JPL by industry participants in the study and sponsors.** The result of the scale adjustments significantly affect only those plants which were much smaller than the 996 million gallon-per-year capacity chosen for the normalization. Thus, the JPL reference case for a TCGP plant of 5000 tons-per-day falls from $3.09 to $2.75/annual gallon, the JPL Lurgi plant falls from $2.75/gallon, the JPL Lurgi plant falls from $2.88 to $2.38/annual gallon and the Hampshire plant (converted to methanol output) falls from $3.23 to $2.96/ annual gallon.

The most interesting comparisons are for the cases shown in row four where both site and scale adjustments have been made. As an overall observation, the capital cost estimates are very consistent. Four Lurgi plants are

* At smaller plant capacities (i.e., below 4000 tons-per-day) the scaling factor would be more significant, falling to perhaps 0.65, however, none of the baseline estimates were this small.

** Information supplied by ARCO, Conoco and Chevron was used to derive this scale factor.

Table 4-3. TOTAL CAPITAL REQUIREMENT (TCR) PER ANNUAL GALLON OF METHANOL OR GASOLINE CAPACITY (1981 $/Annual Gallon)*

SOURCE:	JPL/IND	JPL/IND	JPL/IND	JPL/IND	ORNL	HAMPSHIRE
GASIFICATION TECHNOLOGY:	TCGP	Lurgi	Winkler	Lurgi	Lurgi	Lurgi
BASELINE CAPACITY(10^6/gal):	498	416	746	1120	1200	277**
BASELINE SITE:	Western: U.S. Minemouth	Western: U.S. Developed	Alaska: Cook Inlet	East: Illinois	East: Illinois	Western: U.S. Minemouth
1. Baseline: TCR/Annual Gal Methanol	$3.09	$2.88	$3.31	$2.32	$2.47	$(3.23)
Gasoline	-	-	-	-	-	7.56
2. Baseline: With Western Minemouth Site Adjustment	***	3.29	****	2.65	2.82	***
3. Baseline: With Scale Adjustment to 996 gal/yr	2.75	2.38	3.12	2.36	2.54	(2.96)
4. Baseline: With Site and	2.75	2.82	3.12	2.70	2.91	(2.96)

*The figures in parenthesis represent a conversion from coal-to-methanol-to-gasoline capital requirements to only the coal to menthanol process. This conversion was done using a simple capital adjustment of 85 percent and an efficiency gain of 10 percent (see "Increased Automobile Fuel Efficiency and Synthetic Fuels," Office of Technology Assessment, September 1982, p. 172).

**Capacity refers to millions of gallons per year of gasoline.

***No site adjustment necessary since the estimate was for a Western minemouth site.

****Site was Cook Inlet Alaska near minemouth thus was not adjusted.

shown which vary from $2.70 to $2.96/annual gallon with the reference case used in subsequent analysis at $2.82/annual gallon. For the TCGP case there is also very close agreement with the JPL reference case at $2.75/annual gallon and the ORNL estimate for their TCGP case adapted from coal-to-methanol-to-gasoline estimate at $2.80/annual gallon. In fact, the only plant which is more than 10 percent different from these used in this study is the Cook Inlet case which is $3.12/annual gallon. Actually, the location of the plant in Alaska would easily account for this small difference in capital cost in addition to the fact that it is a less efficient technology which would require additional coal handling facilities relative to most of the other plants. Thus, in our examination of coal-to-methanol plant costs, there seems to be a fairly consistent perception among these very recent estimates that the total capital requirement would be approximately $3/annual gallon for a Western mine-mouth plant of a 500 million gallon per year scale, and that this might be reduced somewhat, to about $2.75/annual gallon if the plant scale is doubled.

b. Near-Term Technology. For commercial plants which might be completed in the late 1980s, we have assumed that the Lurgi Dry Bottom gasifier and methanol synthesis is the appropriate technology on which to base our estimate of coal-to-methanol production costs. This choice is primarily motivated by the full commercial status of this approach in which both Lurgi gasifiers and methanol synthesis units have a successful history of operation.

The key characteristic of this type of process is that the temperature within the gasifier is kept below the ash fusion temperature so the ash can be removed in that form rather than as a slag. As a result, the process is more effective with coals which have a relatively higher ash fusion point (most Western coals have this property). Other important characteristics of this system are:

- Coal is gasified under pressures of 350 to 450 psi.
- Residence time within the gasifier is approximately one hour.
- Product gas has a high methane content.
- Non-caking, high ash fusion temperature coals must be used in this system.
- Devolatilization takes place at 1150° to 1400°F.

The implications of the above characteristics are that because of low operating temperatures, relatively large volumes of by-products are produced (e.g., tar, oil, phenols and ammonia). Second, since the temperature in this system is conducive to methane formation, the Lurgi process is more likely to be used when joint production of methanol and SNG is desired. The system could be modified by adding steam methane reforming of the purge gas to convert the methane into synthesis gas, but this would add complexity and cost to the process. As a result, the application of this technology matches the requirements of electricity and methanol co-production where the methane could be used directly in downstream processes without loss of energy value associated with reducing its pressure and temperature.

As a result of the above considerations, the baseline plant specifications for the near-term Lurgi Dry Bottom technology are as shown in Table 4-4. The key features of the system are: about 56 percent of the output is in the form of medium Btu gas, the overall thermal efficiency is high at 63 percent, and there are significant sulfur and ammonia by-products. It should be noted that this is not suggested to be an optimized plant in terms of product slate, but rather just a representative plant of near-term technology.

Based on the plant characteristics shown in Table 4-4, the capital and operating costs were estimated by industry sources in 1981 dollars and are summarized in Table 4-5. Total capital requirement is approximately $1.2 billion in 1981 dollars with a net operating cost of approximately $152 million annually. The detailed capital cost breakdown of this particular plant concept is shown in Table 4-1 as case B.

The product costs from this type of Lurgi plant under a wide range of assumptions are presented in tables at the end of Section C.3 in this chapter. However, it is useful to present a summary of the production cost results as the technical systems are discussed to make the technology versus cost relationship clear. Thus, following each technical description, a figure will be included which gives the production costs for a reference case* and sensitivities for: lower (15%) return-to-equity, higher (25%) return-to-equity, 85 percent capacity factor, 6 percent product escalation rate, 8 percent feedstock escalation rate, 33 percent higher feedstock base costs, 25 percent greater cost for plant investment and for a 1987 start-up.

A few factors which are particularly important in the production cost analysis from this type of plant are: the Lurgi technology is most suited to co-production of methanol and either MBG or SNG, this technology is proven at commercial scale and thus a modest contingency of 15 percent has been assumed, and because of the low caking tendencies and relatively high ash fusion temperatures of most Western coals they would work well in this system. As a reference case assumption for feedstock, it has been assumed that the delivered cost of coal to a California site would be $38 per ton. A summary of the production cost analysis is shown in Figure 4-1 for the Lurgi Dry Bottom Plant.

Production cost for the reference case is $1.32 per gallon in 1981 dollars for a 1992 start-up. This cost figure is biased upward by the fact that the co-produced product (MBG) was assumed to be valued at the 1992 forecast price of natural gas to a California utility of $6.67/$10^6$Btu. Thus, all the excess costs of production over market value was attributed to the methanol product. Since our emphasis is on methanol, this assumption

* The reference case is discussed in more detail in Section C.2 (Table 4-31) of this chapter. A summary of these assumptions is: 20 percent nominal return-to-equity, 100 percent equity financing, 20-year lifetime, 90 percent plant capacity factor, 1992 start-up, 10 percent investment tax credit, 5 years ACRS depreciation on 95 percent of capital, 8 percent capital cost escalation through 1986 and 7 percent thereafter, 7 percent escalation on O&M, 7 percent escalation on feedstock costs, 2 percent for insurance and local taxes and a combined state and federal income tax rate of 51 percent.

Table 4-4. DRY BOTTOM LURGI COAL-TO-METHANOL PLANT CHARACTERISTICS

PLANT CAPACITY	(10^9 Btu/day)	106.8
METHANOL	(tons-per-day)	2425
	(10^6 gal/year)	242
	(10^9 Btu/day)	47.4
MBG	(10^9Btu/day)	59.4
THERMAL EFFICIENCY		63 %
COAL FEED:	(10^6 tons-per-day)	8564
	(10^6 Btu-per-pound)	9900
BY-PRODUCTS SULFUR	(tpd)	40
AMMONIA	(tpd)	62
CARBON DIOXIDE	(10^6 SCFD)	115
PLANT LOCATION		California
OPERATING FACTOR		0.90
WATER REQUIREMENTS	(gals per minute)	3900
PURCHASED POWER	(megawatt hrs)	78

seems appropriate and it illustrates a problem with this type of technology. Methanol is a higher-value product than MBG on a Btu basis and thus co-production of MBG* is not desirable from a profitability point of view, unless the by-product is competitive on its own merits. In this case, the gas by-product in effect would have to be subsidized by the methanol sales, resulting in a price of $1.32 per gallon. One should not interpret this approach to imply that this process can produce competitive fuel gas, but rather that any by-product can only be sold at its market value.

The sensitivity analysis shows clearly that the required return-to-capital on such capital intensive plants is the key cost driver. At a 15 percent return, the required price is reduced to $0.98 per gallon, while at a 25 percent return, it would increase to $1.76 per gallon. For feedstock costs, an increase in the escalation rate from 7 percent to 8 percent over the plant lifetime increases product cost by $0.06 per gallon, while an increase of 33 percent in basic feedstock cost from $38/ton to $50/ton raises the product cost from $1.32/gal to $1.42/gal. An earlier start-up date (1987) reduces cost to $1.27/gal, since some real escalation in capital cost is avoided.

*Approximately 600/Btu/cubic foot.

Table 4-5. LURGI PLANT COST DATA (millions 1981$)*

CAPITAL REQUIREMENTS	
Erected Plant Cost*	$ 900.0**
Detailed Engr. and Cons't Mgm't	106.2
Owner Admin. and Engr.	34.5
Paid Up Royalties	6.0
Initial Catalysts & Chemicals	6.0
Total Plant Investment	$1052.7
Personnel Training	$ 6.9
Start-up Cost	84.0
Land	0.6
Working Capital	60.0
TOTAL CAPITAL REQUIREMENTS	$1204.2
OPERATING COSTS	
Coal	$ 107.5
Water & Electricity	21.1
Catalysts & Chemicals	2.8
Supv. & Operating Labor	12.2
General & Administrative	3.7
Operating Supplies	0.6
Maintenance	26.3
Insurance	2.6
State & Local Taxes	18.4
By-Product Credits	(43.3)
TOTAL OPERATING COSTS	$ 151.9

*Includes 15 percent contingency

*The data for this particular plant were obtained from one of our study sponsors and checked against the Oak Ridge study cited earlier.

**A detailed breakdown of these erected plant costs can be found in Table 4-1.

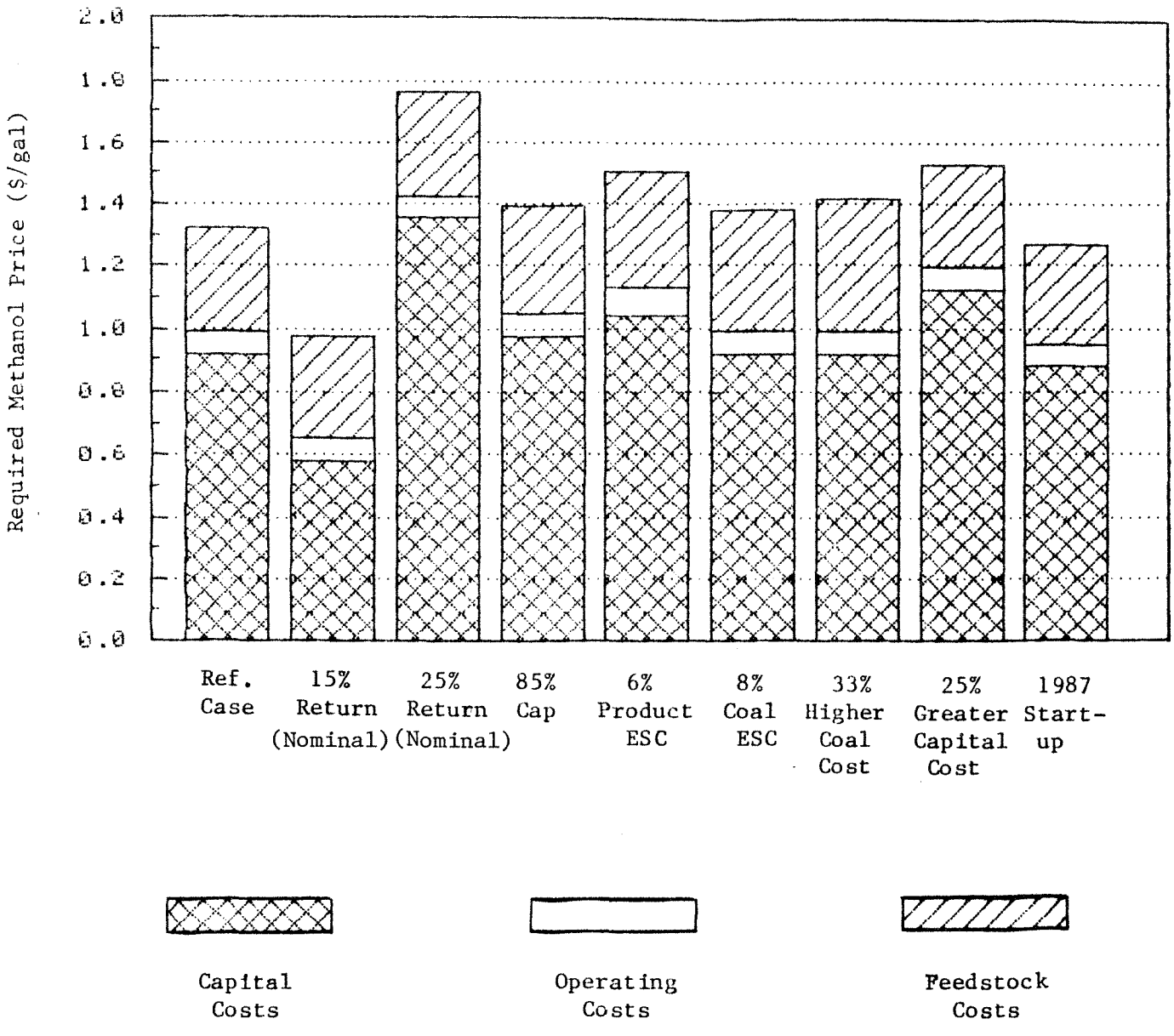


Figure 4-1. LURGI DRY BOTTOM COAL-TO-METHANOL PRODUCTION COSTS SENSITIVITIES (1981 $)

c. Second Generation Technology. In our transition and long-run analysis, we must also consider improvements which will take place in coal gasification technology. There are numerous candidates including: the slagging Lurgi, Koppers-Totzck, Winkler and Texaco Cost Gasification Process (TCGP) technologies.

Technology Options. Each of these second generation technologies offer certain advantages depending upon the coal feedstock available and the desired product. For the purposes of this study, the Texaco Coal Gasification Process (TCGP) process was chosen in our mid-1990's case for methanol from Western coal. This selection was based on four key considerations. First, unlike the Lurgi processes the TCGP technology produces a relatively pure synthesis gas in respect to CO and H_2 content with little or no tars, liquids or other hydrocarbons requiring further conversion, recovery or treatment. While this additional processing (e.g., steam reforming of the purge gas to produce synthesis gas) could be done, it would impose additional capital costs and some efficiency loss. Second, for gasification where further processing is to be done, as in methanol production, it is desirable for the operating pressure to be high enough to provide the makeup synthesis gas at the methanol-synthesis process pressure, thus eliminating the need for makeup gas compression and more process energy. Third, the TCGP process will be demonstrated at commercial scale in the near future (e.g., Cool Water coal gasification plant where 1000 tpd of Western coal will be converted to medium Btu fuel gas). Fourth and finally, this process has been demonstrated at least at small scale to work on Western coals.

Although we selected the TCGP process as the gasification technology for the Western coal case in the mid-term, it is recognized that other processes are more appropriate in particular cases. For instance, if a utility were to co-produce methanol with SNG or medium Btu gas at an electric generating plant, then the Lurgi process may be superior. In the case of utilizing lignites or subbituminous coal in Montana, Texas, or Alaska, the Winkler technology may be the dominant choice for that case. Thus, the selection made here is dictated by a range of considerations peculiar to our West Coast methanol scenario.

Two candidate commercial methanol synthesis processes were considered; ICI and Lurgi. From the standpoint of performance, no major distinction was made. The ICI process was selected as the basis of this study mainly because there are a larger number of commercial plants worldwide using this process. Also, as a matter of convenience, some of the reference studies which were used for cost estimation had also used the ICI process.

Texaco Coal Gasification and ICI Process. The overall production facility is self-contained including the coal-to-methanol plant itself along with the on-site support facilities, utilities, and oxidation process under high pressure using oxygen as the oxidant. A diagram of the coal-to-methanol process is shown below in Figure 4-2.

In the coal preparation process the coal is received, conveyed, crushed and mixed with water to form a pumpable slurry, which is then pumped under pressure into the gasifier. The oxygen process consists of air compression,

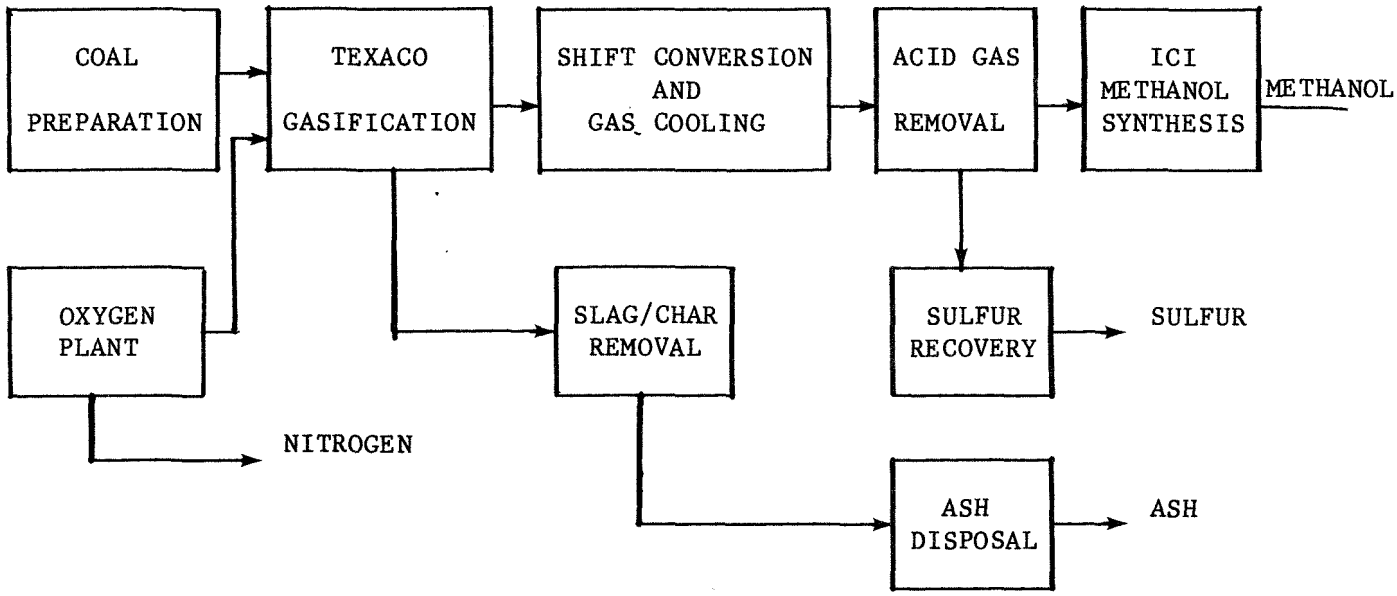


Figure 4-2. COAL-TO-METHANOL PLANT CONFIGURATION

oxygen separation, and oxygen compression to add oxygen to the gasifier for improved combustion. After the gas leaves the gasifier, particulates are removed, the gas is cooled adequately by the quench process which allows unlined steel equipment to be utilized. After shift conversion, the gas passes an acid gas removal process prior to the ICI methanol synthesis loop. The product steam from the overall process is composed of the main methanol product, sulfur, along with by-products and ash. Plant specification and process requirements are summarized in Table 4-6.

Plant Production Rate. Two factors are particularly important to the selection of the plant production rates for early and mid-term coal-to-methanol production plants: economies of scale in gasification and methanol synthesis and considerations of efficient transport quantities. As will be discussed in a latter part of this technical section, the economies of scale in methanol production are significant up to approximately 4000 to 5000 tons-per-day of methanol output. At this level of output one full train is utilized of the critical subsystem processes, thus larger output levels primarily requires a duplicating of the process trains. A second factor in selecting an optimum plant scale is to achieve economies in feedstock and product transport. One of the determining factors for a coal-to-methanol plant using coal shipped to it by rail would be the use of unit train quantitites. A unit load consists of 100 hopper cars, each carrying approximately 100 tons or up to 10,000 tons per trainload. From a bulk transport viewpoint, it would appear that a plant producing 5000 tons-per-day (tpd) of methanol would consume coal in the range of 7000 to 10,000 tpd. Thus, a nominal scale of 5000 tpd methanol output is reasonable in the mid

Table 4-6. TEXACO COAL GASIFICATION - ICI METHANOL SYNTHESIS PLANT SPECIFICATIONS

		PLANT SCALE	
		5000 tpd	10,000 tpd
PLANT CAPACITY	(10^9Btu/day)	97.5	195.0
Methanol Output	(tons-per-day)	5000.0	10,000
	(gallons-per-year)	497.5	995.0
OVERALL THERMAL EFFICIENCY		55%	55%
COAL FEED	(10^6 tons-per-day)	6788	13,576
	(10^6 Btu-per-lb)	12,500	12,500
BY-PRODUCTS: Sulfur	(tons-per-day)	26.0	52.0
PLANT LOCATION		Western Minemouth	Western Minemouth
PURCHASE POWER		None	None
OPERATING FACTOR		90%	90%

term: it captures the most significant scale economies, can be supplied in unit train load, represents a reasonable scale-up in that time period and is appropriately scaled to potential California markets. In our analysis a 10,000 tpd methanol plant will also be costed and evaluated as a possible production option in the longer term (e.g. 1997).

It is also interesting to observe that wherever the plant is sited, i.e., at the coal source or in California, the shipment of methanol by rail tank car could be as high or higher in numbers of cars than the coal coming into the plant. For example, depending upon the tank car capacity, the volume from a 5000 tpd plant would be as shown in Table 4-7. The transport unit cost

Table 4-7. METHANOL TRANSPORT BY RAIL

Gallons/Car	No. of Cars/Day
10,000	150
15,000	100
20,000	75
30,000	50
34,500 (max)	44

of methanol could easily outweigh the advantage of siting the plant at the coal source, depending on how the methanol is shipped and in what unit-size cars.

Pipelining the product methanol from a 5000 tpd plant is not feasible. This would call for only an 8-inch diameter line not fully used over a year's production. For a special case of a single or central consumer, such as a utility, this might be practical over short to moderate distances. Pipelining methanol from a 10,000 tpd plant (about 2000 gpm) would call for a 10-inch line. This size pipeline could be practical from the plant to a central distribution center.

Capital and Operating Costs. The cost estimates used in this study for the Texaco Coal Gasification/ICI methanol synthesis process were obtained from industry sources within the study sponsors and checked against published studies. Thus, although the cost projections are not specific to a particular company, they are representative of those currently being used in the liquid fuels industry to make decisions on methanol projects. The cost estimates are shown below in Table 4-8 for both 5000 tpd and 10,000 tpd plants. The factor used to scale from 5000 tpd to 10,000 tpd was a 0.85 exponential scaling factor, which will be discussed in detail, together with its implications in a later section of this report. Although it does not imply major economies of scale relative to those traditionally achieved in the chemical process industry, it does reflect the limitations of the methanol production technology, which limits single production trains in key subsystems to about 5000 tpd.

Western Coal. In addition to the coal costs shown in Table 4-8 (p. 4-16), which corresponds roughly to a Kaiparowitz (Utah) type coal source delivered to a California plant site, other cases were also considered. For example, other possible Western coal sources are the San Juan Basin (New Mexico) and Rosebud field (Montana). In addition, we have also considered alternative prices for coal which are appropriate to a mine-mouth location for the plant. Coal characteristics and feed rates are summarized below in Table 4-9.

In a general sense, Western coals are more highly reactive, have more oxygen content, and have less sulfur content than Eastern coals. All of these factors are positive for methanol production since gasification cost is

Table 4-9. REQUIRED WESTERN COAL FEED RATES (tpd)

	KAIPAROWITZ		SAN JUAN		ROSEBUD	
	5,000	10,000	5,000	10,000	5,000	10,000
COAL	6,787	13,575	7,872	15,743	7,528	15,056
SULFUR	26	52	49	97	81	162
ASH	440	879	1,267	2,534	683	1,366

Table 4-8. TCGP/ICI METHANOL PLANT AND OPERATING COST SUMMARY*
(millions 1981 $)

COST CATEGORY	PLANT SCALE 5000 tpd	PLANT SCALE 10,000 tpd
CAPITAL REQUIREMENTS		
Erected Plant Cost**	$1,190.6	$2,146.1
Engineering & Construction Management	119.1	214.6
Owner Administration & Engineering	38.8	70.0
Paid-up Royalties	6.8	12.3
Initial Catalyst & Chemicals	6.8	12.3
Total Plant Investment	$1,362.1	$2,455.3
Personnel Training	8.0	10.0
Start-up Cost	93.0	147.5
Land	3.0	5.0
Initial Working Capital	68.1	123.0
TOTAL CAPITAL REQUIREMENTS	$1,534.2	$2,740.8
ANNUAL PLANT OPERATING COSTS		
Coal***	$ 78.4	$156.8
Catalysts & Chemicals	3.4	7.1
Supv. & Operating Labor	14.6	17.4
General & Administrative	4.4	5.2
Operating Supplies	0.7	1.4
Maintenance	34.4	54.5
Insurance	3.4	6.1
State & Local Taxes	24.1	43.1
Sulfur Credit	(0.7)	(1.6)
NET ANNUAL OPERATING COSTS (1981)	$ 162.7	$ 290.0

*The cost data for the 5000 tpd plant was synthesized from data provided by Conoco and Chevron and then checked against independent estimates shown in Table 4-1.
**Includes a 15 percent contingency.
***Other sensitivities will be considered for feedstock cost, in this case $1.30/million Btu delivered to the plant was assumed.

potentially lowered (all else equal) by reducing the size of the oxygen plant and the sulfur removal unit.

d. Coal-To-Methanol Plant Cost Estimates. In comparing our capital costs estimates for coal-to-methanol plants with earlier published studies*, it is clear that our estimates are relatively high. This discrepancy is not simply a matter of increased conservatism, it is attributable primarily to two sources:

- Western plants will cost more to construct than in Eastern locations. This difference is especially important at mine-mouth locations. As a general guideline, location factors will have the following relation to erected plant cost.**

Gulf Coast	1.00
Illinois	1.05
Western Site	1.20
Cook Inlet	1.40

  These differences arise out of added costs of moving men and equipment to remote locations and lower productivity of working in difficult climates with high turn-over rates.

- Perhaps the most "suspect" single factor in estimating plant costs is the scaling factor*** for projecting the cost of larger plants. In many of the studies on methanol conversion we examined, a much more optimistic scaling assumption was made. For example, in the Acurex study**** cited earlier, the scaling exponent was assumed to be 0.6 to reconcile different plant sizes, while the Kentucky Department of Energy derived a 0.73 scale factor. In our view, there is far too much uncertainty at this point about coal-to-methanol production to anticipate significant cost reductions

---

* For example, see Clean Coal Fuels, Acurex Corp., Volume III "Evaluation of Clean Coal Fuels," July 1981, p 3-18; Coal To Methanol, EPRI AP-1962, August 1981, pp 6-18; The Potential for Methanol From Coal, Kentucky Department of Energy, December 1979, p 26.

** These location factors were compiled through discussions with cost analysts at Chevron and Fluor, but the specific values shown are JPL's synthesis of this information. These values have been used to reconcile cost estimates in Table 4-1.

*** The scaling factor (α) is defined as the exponent which is used in the following equation: $C_2 = C_1 (S_2/S_1)$ where C_1 and C_2 are the capital cost of plants one and two respectively, and S_1 and S_2 are their respective coal feed rates.

**** Clean Coal Fuels, Volume III, "Evaluation of Clean Coal Fuels," July 1981.

through economies of scale. This conclusion applies to both economies projected through traditional scaling factors or direct plant estimates at large scale (e.g., Badger report*).

A more reasonable approach at this point in time is to evaluate plants which utilize one full train in gasification, shift conversion, emission controls and coal handling, which is achieved in the 4000 to 5000 tons-per-day of methanol scale. Once experience is gained in an actual production environment, the potential economies of scaling can be better evaluated. Until that point, more conservative projections are warranted. Since plants larger than 5000 tpd would essentially be duplicating production trains, a scaling factor at 0.85 was used in increasing capacity from 5000 to 10,000 tpd.** JPL obtained estimates for scaling factors from three of the project sponsors which ranged from 0.8 to 0.9 for a coal-to-methanol plant larger than 5000 tons-per-day. Also an internal estimate was done by scaling each of the plant sections from 5000 to 10,000 tons-per-day to determine whether new trains had to be added or subsystems could be expanded in scale. Our findings are that of the major process units in a coal-to-methanol plant (coal handling, oxygen production, gasification, methanol synthesis, gas processing and power) only coal handling and power units display major scale economies (i.e., 0.6 scaling factor), whereas the other major process units are nearly proportional to scale (scaling factors of 0.9 to 1.0). Offsite units (mainly utility systems) do display major scale economies in the range of 0.6, but as a result of these economies offsites tend to become a smaller proportion of total plant investment as the plant scale grows.

In scaling up from 5000 tons-per-day to 10,000 tons-per-day, as shown in Table 4-8, JPL has used the following scaling factors applied to the cost categories in Table 4-1. These results, shown in Table 4-10, yield the estimate for the 10,000 ton-per-day plant summarized in Table 4-8.

In an recent study by ORNL*** an estimate was made of scaling coal-to-methanol plant which concluded that a 0.7 scaling factor was appropriate for scaling from an 1800 tons-per-day plant to a 7200 tons-per-day plant. This

---

* Conceptual Design of a Coal To Methanol Plant, Badger Plants Inc., February 1978.

** This scaling factor is, in fact, a derived value specific to methanol production facilities beyond 5000 tpd. Since measured scaling factors vary from under 0.4 to over 1.3 for specific processes, but only average 0.6, it would only be appropriate to use this average if better information were not available.

*** "Liquefaction Technology Assessment - Phase 1: Indirect Liquefaction of Coal-to-Methanol and Gasoline Using Available Technology," Oak Ridge National Laboratory R. M. Wham, et al., ORNL-5664, February 1981, Appendix A, pp. 85-104.

Table 4-10. SCALING FACTORS BY PLANT SECTION FOR TCGP SCALE-UP FROM 5000 TO 10,000, TPD

COST CATEGORY	SCALING FACTOR	10,000 TONS DAY PLANT COST (millions 1981$)
DIRECT FIELD COSTS (DFC)		
Coal Preparation	0.60	$ 94
Air Separation	0.93	276
Gasification	0.95	518
Gas Processing	0.80	110
Acid Gas Removal	0.80	198
Gas Separation	0.80	-
Methanol Synthesis	1.00	184
Reforming & Compression	0.80	-
Emission Control	0.60	108
Steam & Power	0.60	227
Product Storage	0.60	36
Utilities	0.60	100
Offsites	0.60	220
CO_2 Drying & Compression	0.80	75
INDIRECT FIELD COSTS (IFC)	a	285
INDIRECT CAPITAL COSTS (ICC)		
Start-up & Training	b	158
Land	c	5
Working Capital	d	123
Paid-up Royalties	e	12
Initial Catalysts & Chemicals	e	12
TOTAL CAPITAL REQUIREMENT	0.837	$2,741

a Estimated at 13.25% of DFC
b Estimated at 6.5% of DFC plus IFC
c Estimated at $5000 per acre
d Estimated at 5.0% of DFC plus IFC
e Estimated at 0.5% of DFC plus IFC

much lower scaling factor results primarily from the base plant upon which the analysis is done. First, starting from such a relatively small plant, one would expect significant scale economies in process units which would be exhausted at larger scale. We concur that at plant scales below 5000 tons-per-day, scaling factors of 0.65 to 0.70 would be appropriate. Our scaling factor is only appropriate for scaling up from 5000 tons-per-day. Secondly, the scaling analysis done by ORNL was for a Lurgi plant co-producing SNG, which differs significantly from the TCGP plant scaled in this study in the distribution of plant costs among plant sections. One would expect a larger proportion of plant costs in gasification, air separation and methanol synthesis in the TCGP plant, all of which exhibit modest, if any, economies of scale once 5000 tons-per-day of output is reached. The Lurgi plant, on the other hand, has more of its costs in steam and power which have more favorable returns to scale. The net result of these two factors (baseline scale and technology differences) that the apparent disaggrement on scale effects is much less than implied by the absolute scale factors used.

A few points are suggested by our examination of scaling coal-to-methanol plants. First, scaling factors should not be expected to be constant as plant scale is increased significantly. For relatively small plants, the indirect costs for utilities, infrastructure, etc., tend to be a larger proportion of total plant investment and these categories have significant economies of scale ($\alpha = 0.6$). Also, some of the direct process units can be increased in size without proportionally adding additional process trains. At larger plant scales the proportion of offsites to total plant investment tends to diminish and the limit to up-sizing process units is reached. Thus, the scaling factor has a positive relationship to plant scale.* Second, a large part of coal-to-methanol capital cost is in gasification, air separation, and methanol synthesis units which, should have scale factors near unity at 5000 tons-per-day and larger plants, and thus will not likely have major scale economies in these large plants. Third, the technology and plant location will also affect the cost impact of scaling since these factors do influence the relative proportion of plant costs in plant sections which scale relatively well (coal handling, offsites, utilities) versus plant sections which scale relatively poorly (gasification, air separation, methanol synthesis). Thus, for example, small Lurgi gasification plants located at Western mine-mouth locations may show economies of scale ($\alpha = 0.7$ to 0.75) for a wider range of scales than an Eastern TCGP plant. Clearly, site-specific and technology-specific analyses must be done to accurately estimate the cost of major scale changes.

As a means to evaluate the sensitivity of methanol production costs to the potential economies of scale in larger plants, we did consider a lower bound case for the scaling factor. Aside from our baseline estimate (most probable case) of scaling up from 5000 tons-per-day with a scaling factor of 0.84, an alternative case of 0.70 was used with the result shown in Figure 4-3, indicating that scaling is not likely to be a driving factor in coal-to-methanol viability by itself.

e. Production Cost Summary. The production cost calculations for methanol from coal using the TCGP/ICI technology are presented in Section C.4

* Economies of scale diminish at the margin.

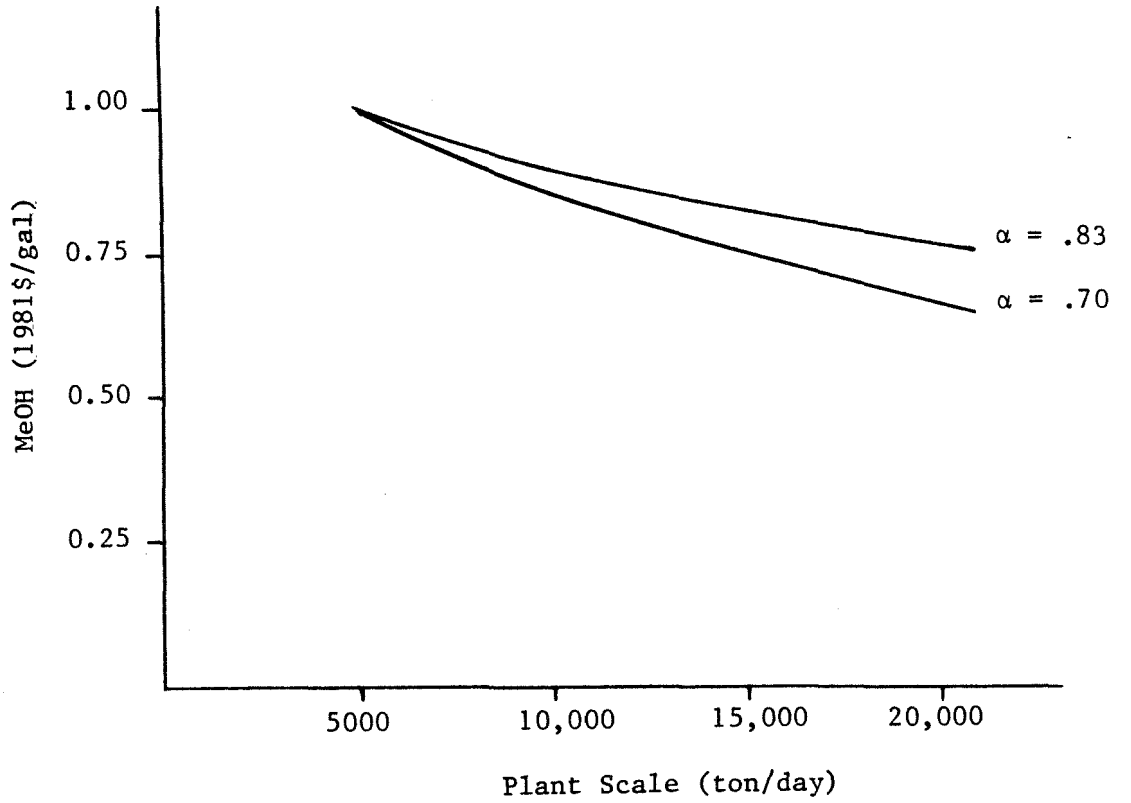


Figure 4-3. SENSITIVITY OF METHANOL PRODUCTION COST TO ECONOMIES OF SCALE

of this chapter. A summary, however, is presented here in Figure 4-3. Compared to the Lurgi system, the most significant difference is that the absence of the large MBG by-product improves the methanol production economics. Under the reference case assumptions, production costs are $1.00/gallon for TCGP/ICI compared to $1.31/gallon for the Lurgi system. As in the earlier case, the return-to-capital is the most significant sensitivity factor, reducing the production cost to $0.73/gal for a 15 percent return and up to $1.36/gal for a 25 percent return.*

Other sensitivities illustrate that changes in feedstock costs are not major drivers of methanol product cost. Raising the escalation rate on coal from 7 percent to 8 percent (from 1% to 2% in real terms) raises the product cost to $1.03/gal, while increasing the initial coal cost 33 percent raises the product cost to $1.05/gal. One factor which does change the production costs significantly is the expected escalation rate for the product. The reference case assumption is that methanol escalates at 8 percent per year, along with expected oil and gas prices. If a company were to assume that

* A 20 percent nominal return, after taxes is the reference case assumption on 100 percent of the investment.

product prices would only keep up with inflation (6%) after operation begins, the initial cost would increase to $1.14/gal.

Similar calculations for the plant represented in Figure 4-4 were done for 10,000 tpd plant to understand the impact of scale on production economics. For the 10,000 tpd, the production costs under the reference case assumptions were $0.90/gal, or about $0.10/gal less than for the 5000 tpd plant. In any event, the potential for these economies to be realized will depend upon successful demonstration of the TCGP process at smaller sale, thus any realization of such economies is far into the future. Our base case scenario to be discussed in the transition analysis is that only a 5000 tpd plant is a realistic candidate for construction in the mid 1990s.*

2. Methanol From Remote Natural Gas

Remote natural gas (RNG) is another potential feedstock for the production of methanol. It is interpreted here to mean natural gas that exists in sufficient quantity to support a full-scale (2000 to 3000 tpd) methanol synthesis facility for several years (10-20 or more), and which is now not readily transportable by pipeline to end-use markets.

There have been many studies and proposals made over the last decade outlining scenarios to exploit gas resources which fit this category. Most of them revolve around the use of offshore barge-mounted plants or prefabricated ocean transported plants. One rather ambitious concept, based on converting Alaskan north slope gas to methanol, involved a very large complex of several units at Prudhoe Bay to produce methanol, sharing 25 percent of the capacity of the Alaska pipeline to Valdez, and ocean tanker transport to California. This alternative is discussed elsewhere in the report in more detail.

The predominant factors involved in the selection of possible systems include: gas sources, locations, production facilities, transportation of product in bulk, technical feasibility and gas cost. It appears that all of the potential sources which are large enough to support a large conversion unit (2000 tons-per-day of methanol and greater) would involve ocean transport either totally or partially. The four main sources considered as most likely after considerable review were:

---

* Although we will not present a detailed description of the plant and process technology, we have also considered one final near to mid-term coal-to-methanol option. That option is Alaskan-Cook Inlet coal, converted using Winkler gasification. The overall capital requirement (in 1981 dollars) for this plant was assumed to be the sum of a total plant investment of $1,624 million and $209 million in other owner costs for a 5000 tpd plant. Net operating and maintenance costs were $43.6 million and feedstock costs were $84.9 million in the base case and $113.2 in the higher feedstock cost sensitivity. The production cost result was $1.13/gal for the reference case assumptions at the plant gate. Although this is higher than the TCGP/ICI case, it must be recalled that transportation costs are not yet added in this part of the report.

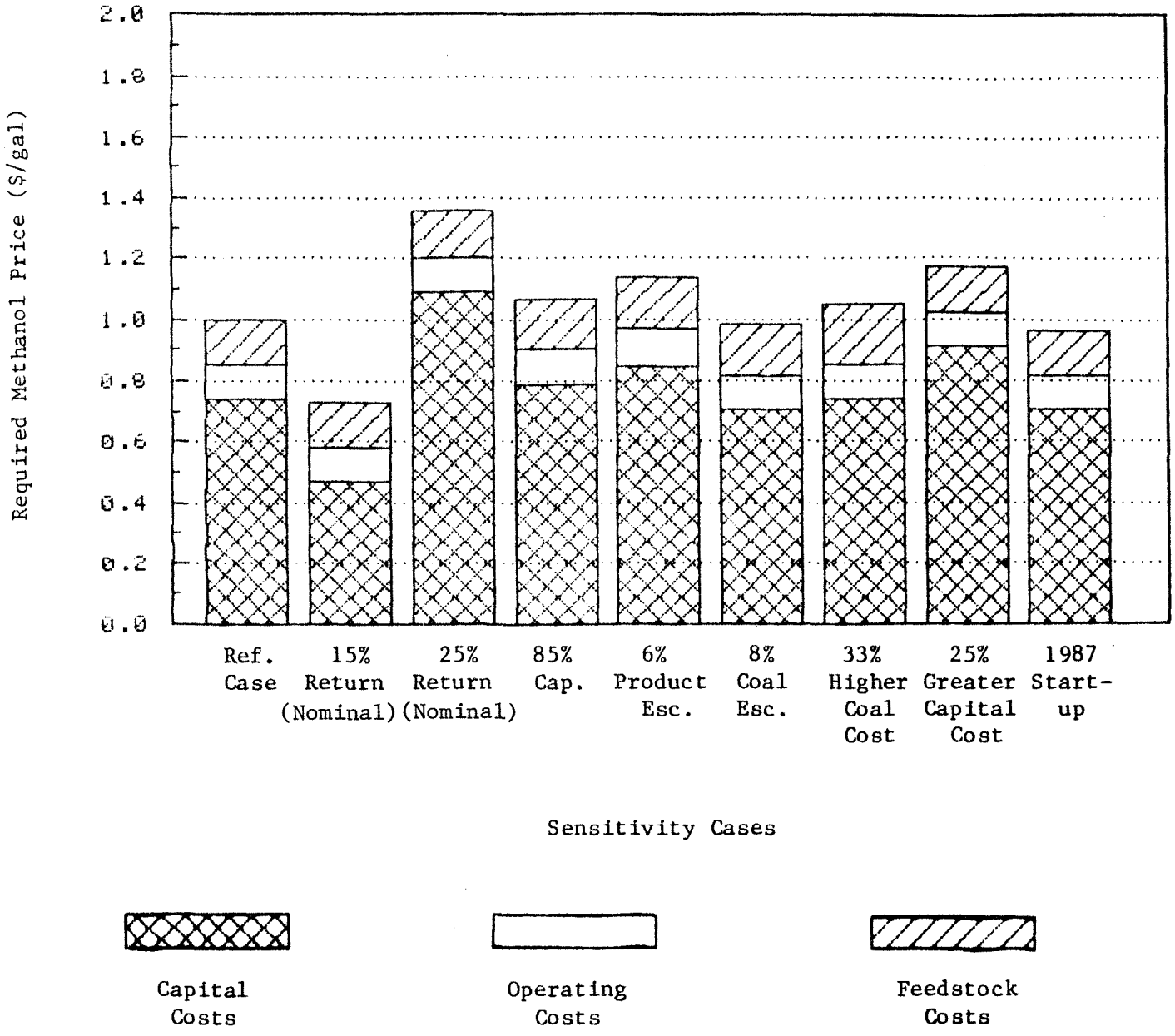


Figure 4-4. TCGP/ICI COAL-TO-METHANOL PRODUCTION COSTS 5000 tpd (1981$)

- o Alaskan North Slope Gas
- o Alaska Cook Inlet
- o Foreign Offshore or Near Shore
- o Canadian and Mexican Sources

a. Alaskan Gas-To-Methanol Sources. The Alaskan methanol concept involves converting natural gas, liberated as a by-product of North Slope oil production, to methanol. The conversion would be at the gas source, i.e., Prudhoe Bay; the methanol would be pipelined, either concurrent with crude oil or in slug flow, to Valdez and then shipped by ocean tankers to Los Angeles for subsequent distribution and use. This concept has been proposed as an alternative to pipelining the gas to the lower 48 states.

The resource, pipeline and tankers involved, dictated a very large system, some 70,000 tons-per-day of methanol product. This volume, over 20 million gallons-per-day, would require a 24-inch pipeline if a separate line were built for the methanol alone. Another concept would be to transport the methanol with crude oil in the existing oil pipeline using 25 percent of that line's capacity, if that capacity were available, which is not likely in the near-term.

The sharing of the existing line has been challenged and may be a weak point to the concept. The necessity of such a large facility all but rules it out as a near-term practicality for methanol for California and thus is not a transition option. The 70,000 tons-per-day would be very large relative to the size of near-term methanol markets in California. For example, this plant would provide about 25 percent of the gasoline equivalent for the year 1990 for the State of California. This seems well in excess of the most optimistic published estimates of the displacement of current fuels even if this were shared with utilities on a fifty-percent basis.

Furthermore, for a facility this large to be economically feasible, it should be able to support its own dedicated pipelines. In addition, the product might be distributed to other Western states. Since this scenario involves such a large quantity of methanol and would therefore require a large market, it is not considered as a near-term transition option for the California Methanol Assessment. In this chapter the focus is upon nearer-term options which involve smaller markets and hence production facilities.

b. Domestic U.S. Western Offshore Gas Sources. The building of methanol plants on barges, floating platforms, used tankers, etc., has been proposed by many companies (Litton, Swedyards, Conoco, Mitsui, et al.) as a means of developing gas reserves in remote areas. An excellent case can be made for such facilities to supply methanol to the U.S. from distant gas sources, such as Indonesia and elsewhere. As the distance increases so does the contribution to methanol cost due to ocean transport.

If the basic concept is valid over long distances, then it should be as valid or more valid for sources closer to the U.S. shores. There would also

be more opportunity for tankers to play a part in collecting and transporting methanol from smaller offshore converting stations which could not justify separate pipelines and land based terminals. The added advantage of a domestic supply versus foreign would be a longer-term strategic factor.

Using a combination of barge-mounted or floating-station plants and tankers servicing several offshore stations and port terminals, the economic plant size might be broadened to include some much smaller than the maximum current land-based plants. The maximum capacity would still be practically unlimited since multiple units could always be employed.

Assuming there is sufficient gas available from several offshore oil stations to provide enough methanol to occupy the unit tankers, the total transport distances could be equivalent to the foreign stations and still be feasible. The concept selected as more favorable than a large Prudhoe Bay plant was an offshore barge at Alaska's Cook Inlet. The advantages are:

- o No major pipeline for product.
- o Flexible plant size.
- o Prefabrication cost savings.
- o U.S. source.

The Litton barge concept* and size was used as a basis for capital and operating cost estimates after it was compared with other estimates. It involves a floating barge fed by gas from a near-shore source producing fuel-grade methanol at a rate of 2,800 metric tons-per-day. From Litton's estimate, the barge would be about 500 ft x 320 ft, would consume about 100 million SCFD of gas, and have on-board storage capacity of 18 million gallons of product.

c. Foreign Off-shore or Near-Shore Gas Sources. A single case was selected and based on the development of a gas supply offshore southeast Asia. It is assumed for purposes of this study that this would be somewhere in Indonesia. Costs of tanker transportation to Los Angeles were taken as proportional to great circle distances in comparing other published estimates from Indonesia to Los Angeles, Yokohama and Gulf Coast, and from Valdez to Los Angeles. No specific site was selected, but the distances were taken as being to Los Angeles from the general area of Djakarta.

This case has been included mainly for its comparative value. It is noted here, however, that this may be an alternate fuel chemically from foreign crude oil-derived fuels, but it remains a foreign source and subject to some hazards of price change and cut-off risks.

---

* Although Litton is no longer in the business, their plant concept and cost data were retained because it is quite consistent with estimates of comparable plants offered by Swedyards and Mitsui. The data on the Litton concept was taken from their publication, "Barge-Mounted Methanol Conversion Plants," Litton Energy Systems; plant cost data obtained from Dr. A. L. Baxley, then of Litton.

As noted above, no specific sites were selected. For the Western U.S. offshore base, the transport distances from offshore stations to Los Angeles was taken from Cook Inlet. For the Indonesian base, the transport distance to Los Angeles is so great, about 9000 great circle statute miles, that slight variations from site to site would be insignificant. There is no basis at this time to allow specific site selection, and the barge-mounted concept is relatively independent of site-specific variables.

d. Barge-Mounted Plant Concept. The use of a floating or barge-mounted facility for chemical processing instead of a land-based plant has been proposed regularly over the past 20 years. Designs have varied from shipboard desalinization units to supply freshwater to arid areas, to converted tankers for chlorine production to barge-mounted ammonia synthesis units. Standard designs are now available from several suppliers for methanol barge-mounted plants, such as Swedyards of Sweden, Mitsui, and others. The concept was developed for remote locations, where land-based construction and overall infrastructure were very expensive or prohibitive. It has been extended to include offshore and near-shore locations and in combination with product tankership transport to get around other difficulties such as lack of pipelines, long construction schedules, etc.

The advantage claimed for this concept include:

- Shorter overall schedule from contract to start-up.
- Economy of shop fabrication and modular construction.
- Elimination or significantly reduced land-site and infrastructure requirement.
- Development of remote resources which would be uneconomic for land-based facilities.
- Overall reduced cost compared to land-based facilities of comparable service in remote locations.

The concept has been developed to a detailed design, and the cost factors have been analyzed and numerous applications considered. It has been generally accepted as technically and economically feasible in many regions of the world but still awaits final applications. The problem up until now has been that with regulated gas in the U.S. and the import duty on chemical market methanol, there has been no economic advantage to such plants. With market gas rising in the U.S. to residual oil prices and fuel applications exempt from the import duty, these plants are potentially more economic in the future.

In the time frame of this study (before 2000), it seems likely that several of these units will be in operation worldwide in the conversion of natural gas to methanol.

In 1976, a study for use of a floating plant for methanol from remote gas was completed by Conoco and Mitsui. It concluded that:

- The concept was technically feasible.

- o The cost of plant and barge was less than land-based plant constructed at remote sites and less subject to unforeseen cost increases.

- o Construction time would be 7 months less than land-based and less subject to unforeseen delays.

- o The concept is applicable to most offshore or near-shore gas resources except areas of severe weather such as the North Sea.

The study was based on a plant producing 2000 tons-per-day of fuel-grade methanol from remote gas in southeast Asia, marketing in Japan and the U.S. and transporting by 45,000 dead weight tons (DWT) tankers.

e. Capacity of Plant Facilities. The base size of a barge-mounted methanol plant used was the design offered by the supplier of a plant with a capacity of 2800 metric tons-per-day (mtpd) or approximately 3100 short tons-per-day (stpd). This was to be served by 30,000 DWT tankers. Assuming 18-days storage capacity on each barge, this translates to about 55,000 to 56,000 tons storage capacity.

A single plant would be the standard design of 2,800 mtpd requiring about 100 million scfd of supply gas. Plants larger than this size would require multiple units which were not considered in this study. Depending upon the location and the distance to Los Angeles, the tanker capacities would be sized based upon round-trip time, storage capacity at the barge, long-term versus short-term optimum costs, etc. This study fixed the tankers at 30,000 DWT for both Alaska and Indonesian locations for simplicity.

A rough calculation shows the round-trip time from Indonesia to Los Angeles would be about 41 days. In that time the 2,800 mtpd plant produces 127,300 short tons. A single tanker would need a capacity, at a minimum, equivalent to 908,800 bbls, or approximately a million barrels. Two tankers would call for a minimum of 63,650 DWT or 454,000 bbls and three would call for 42,400 or 45,000 DWT. For purposes of risk spreading and to allow a certain amount of staggered maintenance so that when one ship is out of service the plant can also schedule maintenance or reduce production to only two-thirds, a fleet was assumed for this study. Operating costs were scaled based on Litton studies for 30,000 DWT tankers operating from Cook Inlet to Los Angeles by adjusting from the longer distances from Indonesia.

f. Production Process Operations. The complete plant includes all the processing stages from gas feedstock intake to the final end product. It also includes all the necessary utility processes, such as electric power generation, steam and fresh water generation. Apart from gas feedstock, chemicals, and catalysts, the plant is completely self-supporting.

The feedstock is natural or associated gas. The natural gas consumption for the plant is about 35,700 SCF per metric ton of methanol. This amount serves not only as feedstock but also as the main energy source for the process plant as well as for the utility and service systems.

g. The Methanol Process. A proprietary process operates on various feedstocks. After desulfurization the feedstock is mixed with steam and passed through a reformer. Heat is recovered and water separated from the process gas thus formed. The gas is compressed before entering the methanol synthesis loop, where it is converted to methanol in proprietary converters. The methanol is separated from the synthesis gas by condensation and then distilled to produce quality requirements.

The utility systems produce all the necessary steam, electrical power, and fresh water for plant operation. Depending on plant requirements, the utility system can include:

- Auxiliary boiler and superheater.
- Sea water desalinization.
- Cooling water.
- Compressed air for instruments and pneumatic tools.
- Inert gas to be used during start-up and shut-down.
- Diesel generator.
- Control and instrument systems with date recorder.
- Fuel systems for auxiliary boiler, superheater, and gas turbine.
- Fire-fighting systems.

A summary of the basic plant specifications and other data is shown below in Table 4-11.

Table 4-11. BARGE-MOUNTED METHANOL PLANT SPECIFICATIONS

PROCESS FLOWS	
Natural Gas Input	100 million ft^3/day
Methanol Output	296 million gallons/year
Storage Capacity	18 million gallons
OVERALL THERMAL EFFICIENCY	57 percent
BARGE SIZE	500 ft x 320 ft
PLANT LAYOUT	two independent parallel trains with common utilities

h. Relative Efficiencies. A coal-fed methanol conversion plant produing a fuel-grade product may have a coal feed-to-product ratio on a weight basis from about 1.55 to about 2.00 lbs/lb. Using 12,000 Btu/lb as the higher heating value (HHV) of the coal feed and 9,763 Btu/lb as the HHV of the product methanol, the overall thermal efficiency, assuming no imported power or fuel and no byproduct heat value, would range from 40 to 50+ percent.

Various natural gas-fed methanol synthesis processes claim gas-feed rates from 26.7 x 10^6Btu/short ton of methanol to 35 x 10^6Btu/ST. Using the same HHV for methanol of 9,763 Btu/lb above, the overall thermal efficiencies range from 52 to 68 percent.

It would appear that from a straight thermal efficiency viewpoint, natural gas-fed plants enjoy an average of 15 percentage points advantage. A gas plant enjoys a lower capital cost by several factors. These advantages are almost totally cancelled by the lower cost of coal on a Btu basis versus conventional natural gas. It becomes clear that gas which may be priced at some opportunity cost near coal on a Btu basis such as remote natural gas, will produce a product which would compete aggressively as a fuel. The added transportation cost component becomes a critical factor in the economic feasibility of methanol fuel, even with a very favorable gas-feed cost. And the relative remoteness to the market will probably determine the ultimate delivered cost and perhaps influence strongly the bid price for remote gas supplies.

Table 4-12. METHANOL PLANTS - BARGE-MOUNTED CONCEPT (millions 1981 $)*

CAPITAL REQUIREMENTS	
Total Plant Investment	$ 350
Contingencies	60
Plant Investment	$ 410
Initial Catalyst & Chemicals	$ 9
Paid-up Royalties	2
Start-up Expense	8
Working Capital	20
Total Capital Requirement	$ 449
OPERATING COSTS	
Operation and Maintenance	$ 42.2
Feedstock Costs** ($1.00/$10^6$Btu)	33.6
Transport Cost***	13.1
Total Operating Costs	$ 88.9

*Cost data supplied by Dr. Al Baxley of Litton Industries and checked against other estimates as shown in Table 4-13.
**At $1.50/$10^6$Btu feedstock cost would be $50.3 million annually.
***For Indonesia it would be $49.5 million per year.

i. Capital, Operating and Product Cost Estimates. The capital and operating cost estimate (Table 4-12) for the RNG barge-mounted plants were based largely upon similar estimates prepared by Litton Energy Systems and supplied to JPL by private communication from Litton. Estimates for barge-mounted plants by other sources when adjusted for scale differences were quite comparable (see Table 4-13 for this comparison).

Adjustments were made to the capital costs in minor areas such as contingencies and format to make these gas-fed plants on the same basis as the estimated coal-fed plants. Treatment of financing costs, rates of return, evaluation, etc., are according to the economic program used for this overall study. Operating costs were taken directly, but the cost of gas was varied over a wide range. Product transportation by ocean tanker was used directly for the Cook Inlet case. This was adjusted for distance and turn-around time to derive a consistent unit rate for the Indonesian case.

In order to verify that the cost estimate used in the analysis for our baseline case was consistent with the best data available, it was compared with other available sources. As a result, plant investment estimates made by Conoco, Mitsubishi, Mitsui, Nissho Iwai, Swedyards and the World Bank were obtained. The comparison in Table 4-13 shows that the estimates are very consistent, with the exception of the Mitsui estimate which seems too low even for construction of a natural gas methanol plant built on the Gulf Coast.

A summary of the production costs of methanol for the barge-mounted concept is shown in Figure 4-5. The reference case assumptions are the same as those used in the coal-to-methanol plants. Significant differences from the earlier cases are attributable to two driving factors. First, the plant

Table 4-13. PLANT INVESTMENT ESTIMATES FOR BARGE-MOUNTED METHANOL PLANTS (1981 $)

ESTIMATE SOURCE	CAPACITY (millions gallons)	PLANT INVESTMENT (millions 1981 $)	PLANT INVESTMENT PER ANNUAL GALLON (1981 $)
Litton*	296	$410	$1.39
Conoco**	211	288	1.36
Company 1**	190	245	1.29
Company 2**	211	220	1.04
Company 3**	207	290	1.40
Company 4**	211	293	1.39
World Bank***	199	295	1.48

*Dr. A. L. Baxley, Litton Energy Systems, 1982.
**Conoco, "Indonesian Gas Utilization Project," 1981. Various estimates by companies which were interested in supplying barges to Conoco, but whose names must remain confidential.
***World Bank, "Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries," 1982.

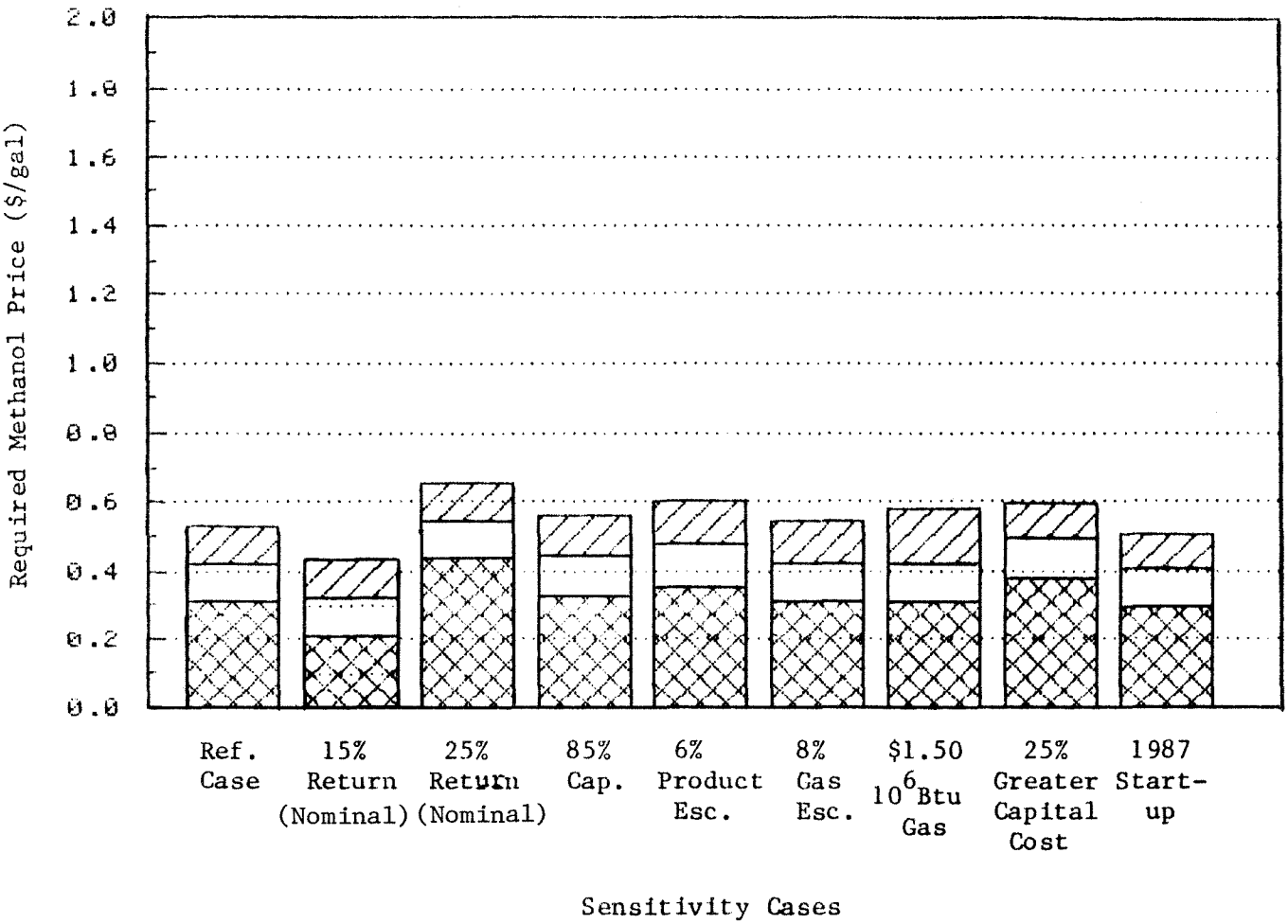


Figure 4-5. REMOTE NATURAL GAS BARGE-MOUNTED PLANT - 3,000 tpd (1981 $)

investment for a natural gas plant is approximately $1.50 per annual gallon of capacity, whereas the coal-to-methanol plants were nearer $3 per annual gallon capacity measured in constant dollars. The second major factor is the higher process efficiency of 65 percent for natural gas plants versus 55 percent for the TCGP process and only 45 percent for the Winkler system operating on Alaskan coal. With the feedstock cost of only $1.00/$10^6$Btu to $1.50/$10^6$ Btu and a higher efficiency, the barge-mounted concept is less expensive on a feedstock basis as well.

The reference case results show $0.53/gal as the plant gate production cost. Decreasing the required return-to-equity to 15 percent decreases the production cost to $0.42/gal, while increasing it to 25 percent raises the production cost to $0.66/gal. Raising the feedstock cost is an important sensitivity since remote natural gas costs will vary significantly depending on both collection costs and the value of the gas in alternative uses. At prices of remote gas of $1.50/$10^6$Btu and $2.00/$10^6$Btu, the production cost rises to $0.58/gal and $0.64/gal, respectively. The barge-mounted concept is less affected by a 25 percent capital cost overrun than the coal plant with much less total investment required. This capital overrun sensitivity is to raise the cost to $0.60/gal from $0.53/gal.

3. California Feedstocks

In the analysis of alternative methanol production technologies for California markets, it is important to consider indigenous feedstocks. In particular, California has two resources which are potentially interesting: petroleum coke and bioenergy. Other potential resources such as California's deposits of heavy oil in rock or residual oil, which becomes available as heavier crudes are refined in the state, are simply too expensive to extract in the former case, or two high in opportunity cost to utilize economically as a methanol feedstock.

a. Petroleum Coke. Petroleum coke is a combustible, solid by-product of coking processes and oil refining. The solid coke contains a very high percentage of carbon, some sulfur, nitrogen and heavy metals. Because of its low reactivity, coke produced from low sulfur crude oils finds wide acceptance for use as metallurgical coke. But as increased quantities of heavy crude oil containing substantial quantities of sulfur are processed in refineries, the coke will not have a preferential value because of its high sulfur content. Its use as a direct fuel in California is preempted, because its combustion products produce excessive air pollutants. Petroleum coke can be easily gasified to produce a clean syngas which can be synthesized to methanol, a high-value clean fuel. Capital and operating costs are summarized in Table 4-14.

In the first case, the cost was estimated as if the plant was a grass-roots facility, while in the second case the plant is assumed to be located right at a refinery site, which is the feedstock source and provides economies in support facilities. In addition, the plant is scaled at 2000 tpd in order to be consistent with the coke by-products at California refineries. Thus, although the plant may appear to be sized small relative to the coal cases, it

Table 4-14. PETROLEUM COKE-TO-METHANOL CAPITAL AND OPERATING COSTS (millions 1981 $)*

	STAND-ALONE PLANT	REFINERY SITE
PROCESS DESCRIPTION		
Feedstock: Petroleum Coke (tpd)	3,100	3,100
Product: Methanol (tpd)	2,000	2,000
Plant Capacity Factor: (%)	90	90
CAPITAL REQUIREMENTS		
Erected Plant Cost	$527.6	$418.0
Engineering & Construction Management	52.0	42.0
Owner Administration & Engineering	17.0	13.6
Prepaid Royalties	3.0	3.0
Initial Catalysts & Chemicals	3.0	3.0
Total Plant Investment	$602.6	$479.6
Personnel Training	3.2	3.2
Start-up Cost	37.2	29.7
Land	-	-
Working Capital	30.1	39.1
TOTAL CAPITAL REQUIREMENTS	$673.1	$542.6
ANNUAL PLANT OPERATING COSTS		
Petroleum Coke ($1.80/10^6$Btu)	$ 55.2	$ 55.2
Catalysts & Chemicals	1.4	1.4
Supv. & Operating Labor	8.2	8.2
General & Administrative	13.7	13.7
Operating Supplies	6.0	6.0
Maintenance	21.1	16.7
Insurance	1.4	1.1
State & Local Taxes	9.2	7.3
TOTAL ANNUAL PLANT OPERATING COSTS	$116.2	$109.6

*Cost Estimate made by JPL using the Texaco Coal gasification and ICI methanol synthesis plant costs described in Table 4-8.

is appropriate to the overall production facility. It is further assumed that the process technology involves TCGP gasification and ICI methanol synthesis processes.

The key considerations in estimating the cost of a petroleum coke-to-methanol facility compared to a coal feedstock is that the plant in the former case would be situated at a refinery site. This location would take advantage of reduced feedstock transportation and achieve economies on certain process trains. For example, the facility could share utility capacity with the refinery operation. Another savings compared to a grassroots coal-to-methanol plant would be the much reduced ash recovery subsystem and reduction in cost for support facilities (roads, security, etc.) being at a developed site.

The production cost summary in Figure 4-6 reveals that petroleum coke would be a fairly high cost methanol option in the nearer-term. The reference case feedstock cost of $\$1.80/10^6$Btu is fairly expensive, although it must be remembered that it represents a delivered cost at a California plant site. In addition, the higher cost compared to the TCGP process is partly attributable to the smaller plant scale (2000 tpd) which is necessitated by the quantity of petroleum coke available at refinery sites. Thus, although performing the production cost sensitivities at a larger-scale plant would reduce the estimated cost somewhat, it would be a meaningless estimate since plants of that scale would not be built. The approach in selecting plant scales for evaluation throughout the study has been to consider the whole end-to-end system from feedstock to final user.

The cost sensitivities are basically self explanatory. First, for the grassroots plant, the return-to-capital is the most important cost driver as evidenced by a reduction from $1.32/gal in the reference case (20% after-tax, nominal return-to-equity) to $1.01/gal with a 15 percent return in comparable terms. Changes in petroleum coke cost from the $\$1.80/10^6$Btu reference case to either $\$2.40/10^6$Btu or $\$1.20/10^6$Btu would result in product costs of $1.41/gal and $1.23/gal, respectively.

For the plant built at the refinery site, the reference case cost is reduced to $1.07/gal. At a 15 percent after-tax return the cost would be $0.86/gal, while at a 25 percent after-tax return the cost would be $1.37/gal. In the case where feedstock could be obtained for $\$1.20/10^6$Btu instead of $\$1.80/10^6$Btu in the reference case, the minimum required revenue falls to $0.99/gal. Thus, it would take a combination of events to bring the petroleum coke case into the competitive range with remote natural gas. If a plant built at a refinery site would be acceptable with a 15 percent after-tax return and the opportunity cost of the petroleum coke were $\$1.20/10^6$Btu, then the required revenue would be approximately $0.78/gal, which is still too high to compete in the near term.

b. Methanol from Biomass. The conversion of biomass feedstocks by thermochemical means generally involves technologies that utilize high temperatures to convert the carbon constituents of the biomass to more useful alternate energy forms, such as:

Combustion: to produce heat, steam, and/or electricity.

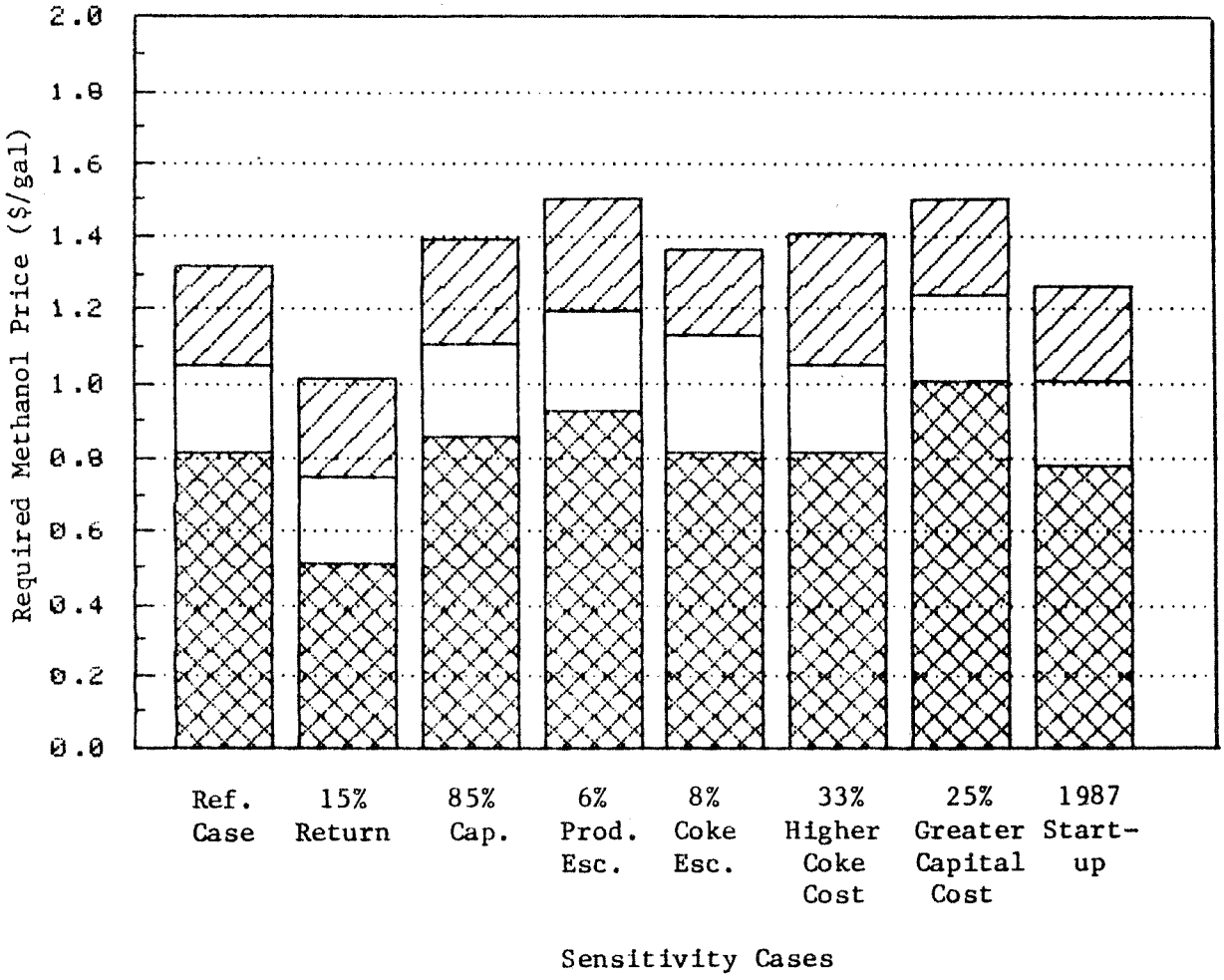


Figure 4-6. PETROLEUM COKE-TO-METHANOL PRODUCTION COSTS 2,000 tpd (1981 $)

Pyrolysis: to produce low or medium Btu gas, liquids, and char.

Gasification: to produce a synthetic gas converted to SNG, methanol, ammonia, and/or Fischer-Tropsch liquids.

Liquefaction: To directly produce gasolines, distillates, and heavy fuel oils.

The alternate biomass feedstocks available to produce the above products include agricultural and industrial wastes as well as wood produced by silviculture, (the intensive controlled farming of cellulosic forms). Agricultural waste products, which are conducive to a central gathering or collection depot with minimum gathering or transportation costs and in sufficiently large quantities to construct and build economical conversion facilities, include corn stover, corn cobs, sugar cane bagasse, rice and wheat husks, and straw. Industrial waste products with similar parameters to the above agricultural wastes include municipal solid wastes, pulp mill wastes, sawdust, and the residue left after wood harvesting.

Feedstock Selection. The feedstock options for methanol from biomass involve utilizing agricultural and industrial wastes or production of a biomass feedstock by silviculture methods. In the latter alternative, technologies are employed similar to growing agricultural crops, including systematic intensive planting, fertilizing, cropping, and selective harvesting of the material. In the near future, the feedstocks which are considered to have the highest potential for thermochemical conversion are woody plants and trees. Using waste products tends to constrain the scale of the conversion facility because of rapidly rising transport costs of collecting dispersed residues for feedstock. Thus, in order to achieve overall system economies, the more energy intensive silviculture forms are assumed.

Wood consists principally of cellulose and lignin. An analysis of wood on a dry basis shows the carbon content to be about 50 percent, the hydrogen content about 6 percent, and the oxygen content varying from 35 to 40 percent. Sulfur and nitrogen contents are very low, and ash content varies from 0.1 to 3 percent. The analysis of wood used in this assessment is indicated in Table 4-15.

The moisture content of green wood varies from 50 to 60 percent on a weight basis. Field drying of wood reduces this to about 20 percent moisture. For purposes of this evaluation, the moisture content of the wood, as received, was considered to be 50 percent on a weight basis.

Conversion Facilities. The conversion of wood biomass to methanol can probably be accomplished with commercial fixed bed gasifiers, although there would be costs associated with cleaning tars and oils from the gas. Development of advanced gasifiers which maximize the co-hydrogen yields and reduce tar and oil formation would therefore improve costs significantly.

Other gasifier technologies considered for wood gasification were the fixed (moving bed), fluidized bed, entrained, molten bath-type, and catalytic

Table 4-15. ANALYSIS OF WOOD FEEDSTOCK

	ULTIMATE ANALYSIS (wt. %)
Carbon	54
Hydrogen	6
Oxygen	38
Nitrogen	0.2
Sulfur	0.1
Ash	2
TOTAL	100%
Higher Heating Value Btu/lb	9000
10^6 MBtu/dry ton	18

gasification reactors. Most of these options are in very early stages of development and will not become commercially available during this decade, the exception being fluid bed gasifiers. Although those systems currently operate at atmospheric pressures, they will undoubtedly be adapted to operate at high pressure for synthesis to methanol since this reduces the cost needed for syngas compression. In summary, then, low-pressure fixed-bed gasification is assumed in the near-term with a shift to high-pressure technology by the mid-1990s.

Process Description. The following facilities process 2000 tpd (wet) of wood to produce 570 tpd of methanol fuel. The wood is gasified in a 500 psi fixed-bed gasifier along with 500-tpd 98 percent oxygen. The resultant syngas is synthesized to methanol by the ICI methanol synthesis process. The overall energy balance of the system is assumed to be 55 percent, including process energy and feedstock in relation to methanol output. The overall plant and operating cost data for the system are summarized in Table 4-16. This cost estimate was derived from work done by JPL as part of another study* for DOE. As a way to verify its accuracy, it was checked against a comprehensive study** of fuels from biological processes done by the Office of Technology Assessment. In that study the total plant investment of a wood-to-methanol plant was estimated at $88 million in 1979

* Gershman, R., Dutzi, E. J., Ekman, K. R., and Walton, A. L., Methodology Development for Evaluation of Bioenergy R&D Options, Jet Propulsion Laboratory, JPL D-282, September 1982.

** Energy from Biological Processes, Volume II - Technical and Environmental Analyses, Office of Technology Assessment, Washington, D. C., September 1980, pp. 139-141.

Table 4-16. WOOD-TO-METHANOL PLANT AND OPERATING COST SUMMARY
(millions 1981 $)

PROCESS DESCRIPTION	
Methanol Output (tpd)	575
Wood Feedstock (dry short tons)	1,000
Construction Schedule (%/yr)	20,40,40
CAPITAL REQUIREMENTS	
Erected Plant Cost*	$149.9
Engineering and Construction Management	15.0
Prepaid Royalties	0.7
Initial Catalysts and Chemicals	0.7
Total Plant Investment	$166.3
Personnel Training	1.0
Start-up Cost	8.3
Land	0.5
Working Capital	8.3
TOTAL CAPITAL REQUIREMENT	$184.4
ANNUAL OPERATING COSTS	
Feedstock	$ 10.6
Catalysts & Chemicals	0.8
Supv. & Operating Labor	5.2
General & Administrative	3.2
Operating Supplies	1.9
Maintenance	2.9
State & Local Taxes	2.9
Insurance	0.4
TOTAL ANNUAL COSTS	$ 30.5

*Includes 15 percent contingency.

dollars for a 40 million gallon-per-year plant. This estimate is equivalent to $111 million in 1981 dollars or $2.78 per annual gallon. The JPL estimate for total plant investment is $166.3 million or $2.91 per annual gallon. Thus, the JPL estimate is consistent (less than 5 percent difference) with the OTA estimate, although it was derived independently.

Production Costs. The production costs from biomass feedstocks are heavily influenced by the non-availability of a gasifier specifically designed for this feedstock in small-scale operations. Results in Figure 4-7, therefore, are applicable to "commercial" technology and will probably be improved with time. In the reference case, the production cost estimate is $1.12/gal, which decreases to $0.89/gal with a 15 percent return. An increase of 33 percent in feedstock cost from $16/ton (wet) to $21/ton increases the production cost to $1.18/gal. The impact of a capital cost overrun of 25 percent is quite significant, as it raises the methanol cost to $1.27/gal.

Although these plant-gate costs are high relative to remote natural gas, it must be considered that there are tax credits which may make wood-based methanol viable for certain small-scale applications. There is also the potential for new technology to reduce costs through innovative concepts designed specifically for wood feedstocks. The Energy Systems Division at International Harvester, for example, is working on a gasifier which would be manufactured and delivered to the plant site needing only modest site development. Through personal communication from International Harvester we have been informed that the estimated cost of the system they are developing is approximately $7.4 million investment cost, $2.24 million annual operations and maintenance cost, and $1.37 million in feedstock cost. Methanol production from this system would be 6.7 million gallons-per-year. If these figures are taken as accurate (JPL has no way to verify their accuracy since the gasifier is proprietary), the resultant cost of methanol is $0.62/gal in 1981 dollars. This cost is without any adjustment for bioenergy credits, which would reduce costs further. Obviously, this concept could be important in the near term if the system is developed with the cost and performance goals now envisioned. It would be very speculative at this point for JPL to make any prediction on whether there is a reasonable likelihood for this to occur, since we do not have access to the proprietary information necessary to evaluate the system in detail.

4. Advanced Technology

One of the more interesting advanced concepts which might lower the cost of methanol production in the long run is by means of the once-through methanol process associated with an integrated combined-cycle coal gasification plant. This concept has been studied by the Fluor Corporation for EPRI* and offers the following advantages: (1) by employing a once-through methanol synthesis process, the overall methanol conversion efficiency can be raised to

* Economic Evaluation of the Co-production of Methanol and Electricity with Texaco Gasification - Combined Cycle Systems," Electric Power Research Institute, EPRI Report AP 2212, January 1982.

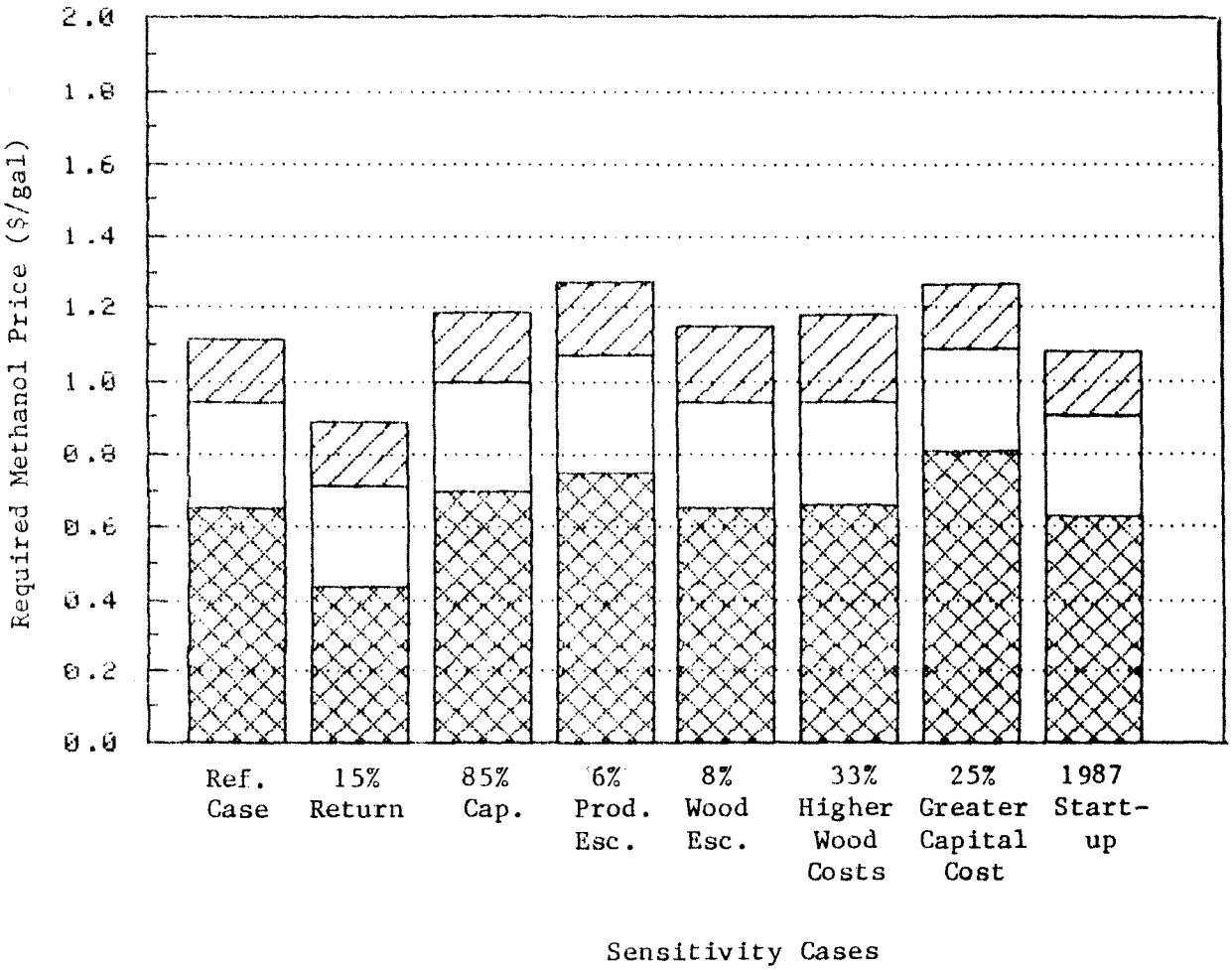


Figure 4-7. WOOD-TO-METHANOL PRODUCTION COSTS 575 tpd (1981 $)

68.8 percent from 57 percent in a dedicated coal-to-methanol plant, (2) unconverted synthesis gas is not recycled to methanol reactors, thereby eliminating power for compression of recycled gas, (3) energy is also saved by avoiding the need for gas shifting, and (4) heat liberated during methanol synthesis can be fully utilized in the power plant's steam system. Thus, there is potentially some real gains which can be made in the cost of methanol production, but this result relies on a few key qualifications: (1) new technology for once-through methanol synthesis must be developed, since this concept currently exists only at the small laboratory scale, (2) electricity from the combined-cycle coal gasification plant must be competitive on its own to justify the add-on methanol synthesis unit, and (3) the gasification concept has yet to be demonstrated on a large scale. If these obstacles can be satisfactorily overcome, Fluor has estimated that approximately a 30-percent cost reduction in methanol could be achieved with a utility-owned plant co-producing methanol and electricity versus a privately-owned dedicated methanol plant. Of this 30-percent cost reduction, Fluor attributes about 18 percent to efficiency improvements and 12 percent to lower financing costs. Although these cost figures are quite soft, given the state of technology development for this system, it is certainly a concept with merit which deserves further research and development effort. Given its current status, it would seem unlikely to be fully commercial as an integrated system until the mid to late 1990s.

C. SYNTHETIC FUEL ALTERNATIVES

Since the nation is examining many synfuels as alternatives to imported petroleum, methanol must compete against a whole range of alternatives which may become available in the next few decades. The uncertainties surrounding many of these options are very great, however, as process development must be completed in some cases and none have operated at commercial scale in the U.S. Thus, the cost ranges and comparisons developed in this section are primarily useful to determine if some options are dominated by others in the near- or mid-term. In this context, the term "dominated" is used to mean that those options do not appear competitive with others under a very wide set of future conditions. The greatest potential for discovering these relationships is where sequential processing steps are required for making higher quality products for the same applications.* It is also necessary to stress that JPL has not made cost estimates of any of these processes. An attempt has been made at obtaining the best public data available and making some adjustments in escalation, start date, and feedstock cost in order to make comparisons with the methanol production costs described earlier in this chapter.

The synfuels which are most interesting for comparison with methanol as a fuel for both vehicles and stationary applications are:

Transportation Fuels:
- Shale oil
- Fischer-Tropsch Indirect Liquifaction
- Direct Liquefaction
- M-Gas

Stationary Application Fuels:
- Liquefied Natural Gas
- Medium Btu Coal Gasification
- High Btu Coal Gasification

With the exception of shale oil and LNG, which originate from distinct feedstocks, the remaining synfuels can be synthesized from coal and thus are related to one another in a processing sense. A diagram which illustrates this product flow is shown in Figure 4-8, where rectangles indicate processes and circles indicate fuel products. In order to make these comparisons consistent, and therefore meaningfuel, there have been a large number of assumptions made which are summarized in Table 4-17.

The format for making the comparisons will be to give a brief description of each process and then give the capital and operating cost data. Product costs will be listed in tables for all fuels in Section C of this chapter, but figures will be presented with each synfuel description to summarize the results. The basis of the plant estimates is for large-scale plants, which implies that earlier development work at smaller scale (pilot plants) have been successfully completed. In addition, there is an implicit assumption that rapid cost escalation due to bottlenecks in construction and engineering does not take place. In the future evolution of the synfuels industry, the plant cost of various options will tend to accelerate if

* Obvious examples are using medium Btu gas or methanol in utility applications or using methanol or M-gas in vehicles.

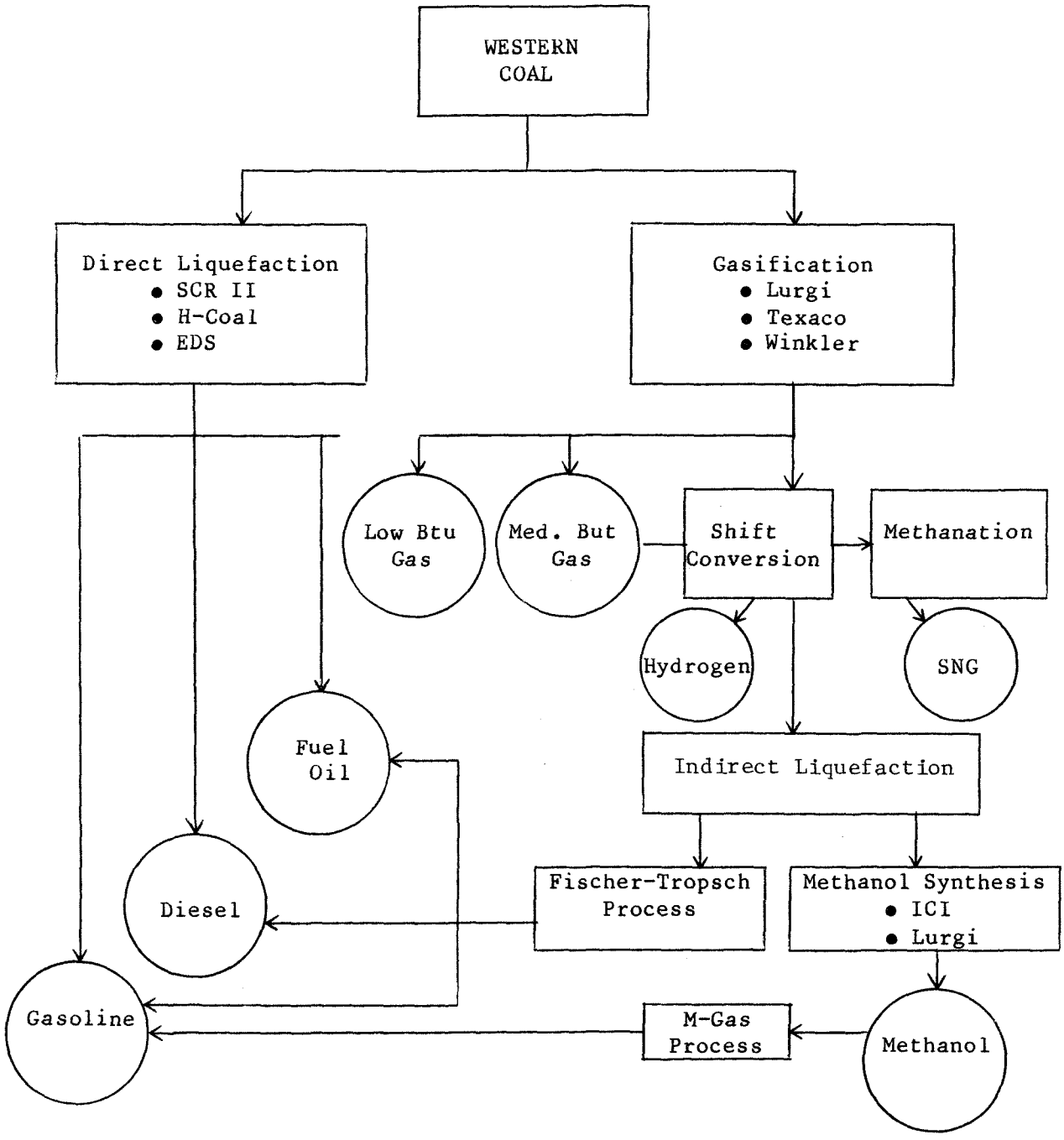


Figure 4-8. SYNFUEL PRODUCTS FROM COAL

Table 4-17. SYNFUEL PLANTS TECHNICAL ASSUMPTIONS

DESCRIPTION	VALUE
Plant Location	Utah - Minemouth
Plant Capacity	
Gasification	250 10^9 Btu/day Product
Liquefaction	25,000 tpd coal feed
Operating Basis	90% (330 days per year)
Project Operating Life	20 years
Commercial Operating Date	1992
Construction Expenditure Rate	
Year 1	10
Year 2	20
Year 3	30
Year 4	20
Year 5	20
Coal Feedstock	
Source	Kaiparowitz
Btu/lb	12,500
Energy Content (10^6Btu)	
Barrel of Oil Equivalent	5.8

expansion takes place too rapidly in a particular option. Some bottlenecks (e.g., engineering and design) affect most synfuel projects equally while others are more specific to a particular option (e.g., acquiring water rights for shale plants). In this study it was not possible to examine the alternative scenarios sufficiently to take into account these second order impacts.

1. Shale Oil

Within the Western states of Colorado, Utah, and Wyoming, there are high grade* deposits of oil shale with the equivalent of nearly three-quarters of a trillion barrels of oil. These Western sources cover approximately 25,000 square miles in mostly remote areas.

* 20 to 30 gallons of oil per ton of shale.

Two basic approaches are being studied for shale oil recovery: above-ground retorting and in-situ gasification. In the former approach, the shale is mined, crushed and transported to the retorting facility to break down the kerogen in the shale and finally the organic vapors are condensed to form a usable feedstock. With the leading in-situ concepts, the shale is fractured underground, heated (either with self-combustion or by an external source) to break down the kerogen, and the vapors and condensates are brought to the surface. Because it is further along in development, the focus in this report will be on the surface retorting technology. A number of technical approaches have been suggested for above-ground retorting, but there is limited commercial experience and none is likely to be economic at current oil prices.

A major issue in shale oil development is the cost of providing offsite support facilities or infrastructure development. In this case, these costs are included in the basic capital cost estimate* (Table 4-18) along with production-related support facilities. Costs of building such plants have changed quite rapidly in the past year as more detailed engineering and cost estimating have been completed.**

The cost data in Table 4-18, when adjusted for escalation and interests costs during construction, bring the total capital requirement at the date of commercial operation to nearly $5.4 billion. At this plant cost, the crude oil product from shale is quite expensive relative to 1982 oil prices. Obviously, a great deal of uncertainty exists concerning the eventual cost of such a facility as indicated by the substantial disagreement between TOSCO and Exxon concerning the Colony project. In order to reflect this uncertainty, we have made a sensitivity calculation with a 25 percent additional capital cost to our reference estimate and consider only the cost range as meaningful.

In order to provide a check on the cost estimate developed by Bechtel,* a recent source was obtained late in this study from the Office of Technology Assessment*** which expanded upon a major assessment**** of oil shale

---

* Cost of plant and operating equipment for all the synfuels comparisons were drawn from the following reports which were updated to 1981 dollars and put on a consistent basis.

a. Acurex Corp., Alternative Fuel Strategies for Stationary and Mobile Engines: Evaluation of Clean Coal Fuels, Volume III, July 1981.
b. Bechtel, Economic Feasibility of Synthetic Fuels Projects, November 1981.
c. ESCOE, Coal Conversion Comparisons, DOE EF-77-C-C1-2468, July 1979.
d. ESCOE, Synthetic Fuels Summary, DOE DE-AC01-77-ET-10679, March 1981.

** The estimate for the Colony project prepared by TOSCO in January 1982 was for $3.77 billion while the Exxon, U.S.A. estimate also in January 1982 was $4.94 billion and the Exxon Research and Engineering's estimate is $5.3 billion for the 50,000 barrel per day facility.

*** Office of Technology Assessment, "Increased Automotive Fuel Efficiency and Synthetic Fuels," September 1982, pp. 170-172.

**** Office of Technology Assessment, "An Assessment of Oil Shale Technologies," pp. 179-200.

Table 4-18. SHALE OIL PLANT AND OPERATING COSTS (millions 1981 $)*

PROCESS CHARACTERISTICS	
Output (bbls. per day)	50,000
CAPITAL REQUIREMENTS	
Erected Plant Costs	$2,100
Infrastructure Investments	734
Engineering and Construction Management	210
Start-up Costs	75
Working Capital	105
TOTAL CAPITAL REQUIREMENT	$3,224
ANNUAL OPERATING COSTS (1981 $)	$ 273
CAPITAL COST (1981 $/BOE)**	$64,480

*Bechtel, 1981; Office of Technology Assessment, 1982.

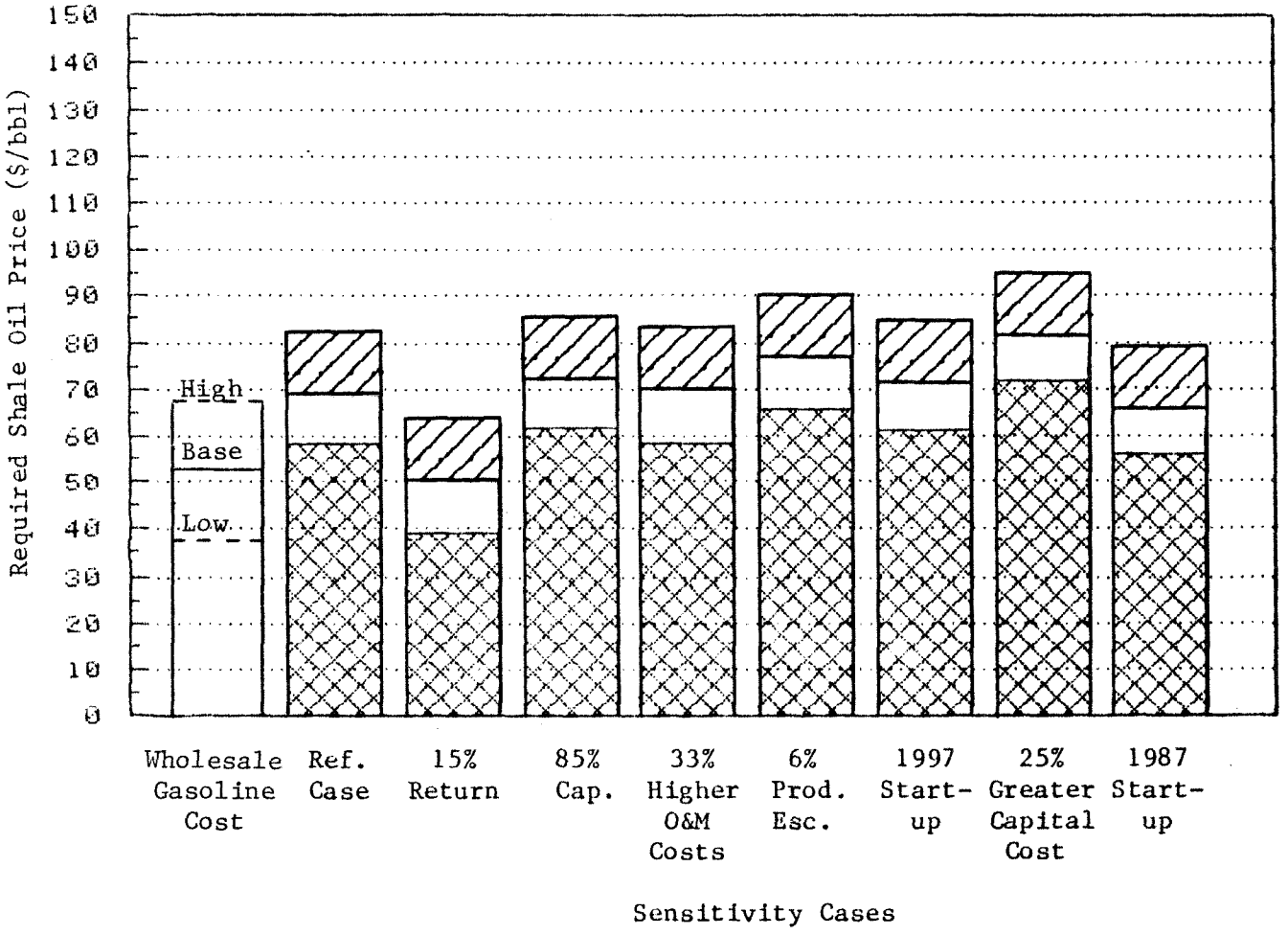
**As a means to compare alternative synfuel processes a summary value of capital costs in 1981 dollars per annual Barrel of Oil Equivalent (5.8 million Btu) will be calculated.

technology completed in 1980. The most recent OTA cost estimate for shale capital cost is in the range $2.6 to $3.5 billion after adjusting to 1981 dollars. This capital cost is consistent with the estimate in Table 4-18.

As shown in Figure 4-9, the reference case results for shale oil production costs are $72/bbl in terms of upgrading the shale oil to gasoline. The reference case in crude shale oil terms is $60/bbl. The adjustment to gasoline was made to facilitate the comparison with methanol, methanol-to-gasoline, and Fischer-Tropsch liquids.

Also shown on the left-hand side of Figure 4-9 is the projected cost of wholesale gasoline in 1992 on a per barrel basis in 1981 dollars. The base case assumption (solid line in bar graph) is $52.50/bbl with the pessimistic scenario price at $68/bbl and optimistic scenario price at $38/bbl. The basis for these alternative price scenarios is discussed in Section III.C of the Summary Report. These estimates are presented just to give a basis of comparison for the synfuel estimates.

The only case which appears to produce comparable costs in the 1992 time frame is where the return-to-equity is 15 prcent which results in wholesale gasoline from shale per barrel at a cost of $50/bbl and a crude shale cost of $41/bbl. The other cost sensitivities of higher O&M costs, 25 percent capital cost overrun, and slower product price growth, all increase the shale-to-gasoline cost to over $70/bbl and over $60/bbl for crude shale oil. In all the shale sensitivity cases, the feedstock is treated as an operations cost



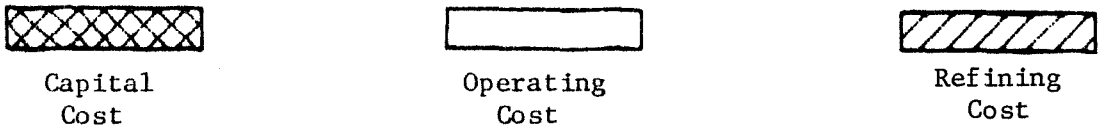


Figure 4-9. 1992 SHALE OIL-TO-GASOLINE PRODUCTION COSTS 50,000 BPD (1981 $)

and thus does not appear as a separate entity. Thus, even in 1992 shale oil will be above the price of conventional oil and gasoline in the baseline scenario at a 20 percent return requirement.

2. Coal Gasification

As illustrated in Figure 4-8, coal gasification is the first processing step to producing a wide range of products. Low Btu gas, which is composed of carbon monoxide, hydrogen and nitrogen having a Btu content of 100 to 200 per standard cubic foot (SCF), can be used as a fuel or further processed into hydrogen. Another possible product, medium Btu or synthesis gas, contains approximately 200 to 600 Btu/SCF and can be further processed into ammonia, methanol or hydrocarbons, or used directly as an industrial fuel or chemical feedstock. The higher quality product, high Btu gas or substitute natural gas (SNG), can be produced through methanation, which converts carbon monoxide and hydrogen to methane (600 to 1000 Btu/SCF) in the presence of a platinum catalyst. This last product can be mixed with natural gas and pipelined for use in utility, industrial or residential applications.

Many gasification systems exist, including moving bed, fluidized bed and entrained suspension concepts. They differ with respect to size of coal feed, flow of reactants and products, residence time of coal particles, reaction temperatures and pressure.

The Lurgi gasifier has been used in the gasification cost analysis because it is fully commercial and can be used on a variety of western coals. The basic data was obtained from Acurex, ESCOE, and Bechtel, and then modified to be consistent with the assumptions utilized in our methanol plant estimates. All costs in Table 4-19 are in 1981 dollars; contingencies are as indicated in the footnotes for each process. The sources used for estimating the plant costs for the high and medium Btu gas cases are shown in Table 4-19. Adjustments have already been made to place all the figures in 1981 dollars and to adjust for construction at a Western mine-mouth site (where needed).

None of the cost estimates in Table 4-19 are based upon definitive engineering and design cost studies, thus, the discrepencies among them are not surprising. The range estimated by OTA does bound the three estimates obtained for high Btu gasification even though the OTA estimates were based on different scenarios. As a result, we feel these estimates are representative of the best data publicly available. As more detailed engineering and design takes place and actual experience is obtained (e.g., Coolwater), the accuracy of the estimates will improve. Based on the experience that more detailed engineering for site specific plants has resulted in higher cost estimates,* it is our judgement that cost figures near the upper end of the range in Table 4-20 should be used for planning purposes and even then a range of capital

---

*Merrow, E. W., Chapel, S. W., and Worthing, C., A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants, R-2481-DOE, RAND Corporation, Santa Monica, Calif., July 1979.

Table 4-19. CAPITAL INVESTMENT ESTIMATES FOR COAL GASIFICATION PLANTS (1981$)

SOURCE	PLANT TYPE	CAPACITY (10^9 Btu PER STEAM DRY)	CAPITAL REQUIREMENT (millions 1981 $)	CAPITAL COST PER DAILY BARREL OF OIL EQUIVALENT (1981 $)
Bechtel*	High Btu	250	$2,500	$58,000
Acurex**	High Btu (Lurgi DB)	216	2,134	57,350
DOE***	High Btu (Lurgi)	250	2,147	49,800
OTA****	High Btu	290	2,350 - 3,019	47,000 - 60,400
Bechtel*	Medium Btu	250	1,790	41,500
DOE***	Medium Btu	282	1,919	39,500

*Bechtel, "Economic Feasibility of Synthetic Fuels," November 1981.

**Acurex Corp., "Alternative Strategies for Stationary and Mobile Engines: Evaluation of Clean Coal Fuels," Volume III, July 1981.

***U.S. Department of Energy, "Cost Factors: Capital and Operations and Maintenance Factors of Representative Energy Systems and Facilities," DOE/MA-0063, Vol 3, April 1982.

****Office of Technology Assessment, "Increased Automobile Efficiency and Synthetic Fuels: Alternatives for Reducing Imports," September 1982.

costs should be used for decision making. As a result of these considerations, the cost figures in Table 4-20 which have been used for the baseline coal gasification estimates are consistent with the Bechtel estimate in Table 4-20, with approximately $58,000 and $41,500 per daily barrel of oil equivalent for high and medium Btu gasification, respectively.

Using the plant cost and operating data in Table 4-20, the production cost estimates for each of these gasification options has been made and summarized in Figures 4-10 and 4-11 for the SNG, and MBG plants, respectively. In each of these figures, the left-hand bar represents the likely competition in terms of natural gas to California utilities. In the reference case

Table 4-20. PLANT INVESTMENT AND OPERATING COSTS* FOR COAL GASIFICATION (millions 1981 $)

	LURGI (SNG)	LURGI (MBG)
PROCESS FLOW:		
Coal Input (tpd at 16.6x/10^6Btu/ton)	27,500	27,500
Yields: MBG (10^6Btu/stream day)	-	282
SNG (10^6Btu/stream day)	245	-
Phenol (BPD)	702	960
Naptha (BPD)	763	-
Tar Oil (BPD)	1,640	1,645
OVERALL THERMAL EFFICIENCY	57%	65%
CAPITAL REQUIREMENTS (10^6 1981$)		
Total Plant Investment**	$2,034	$1,771
Other Owner Costs	$575	$501
TOTAL CAPITAL REQUIREMENTS	$2,609	$2,272
1981 $/BOE***	$58,000	$44,700
OPERATING COSTS (10^6 1981$):		
Feedstock****	$124.6	$129.3
O&M	$128.6	$124.6

*Synthesis of data in Table 4-19 and sources for Table 4-19.
**Includes 15 percent contingency for Lurgi Dry Bottom and 20 percent contingency for Lurgi Slagger.
***BOE stands barrel of crude oil equivalent at 5.8 million Btu per barrel.
****At $0.80/$10^6$Btu mine-mouth coal price, also evaluated at $1.10 and $1.40/$10^6$Btu.

assumptions, none of the plants appear competitive in the 1992 time frame with the base case scenario of gas costing $6.68/$10^6$Btu to California utilities in 1992 in 1981 dollars. The higher bound of $7.51/$10^6$Btu and the lower bound estimate of $4.38/$10^6$Btu, all in 1981 dollars represent the pessimistic and optimistic scenarios, respectively, discussed in Section III.C of the summary report. Even in the case of a 15 percent return,* the medium Btu gas case and the Lurgi SNG Plants produce gas at costs above the base case costs of natural gas. Only utilities with their types of financing** would find

* Nominal, after-taxes.

** In leveraged financing cases the nominal return in our terms which would be consistent with utilities would be approximately 12 percent.

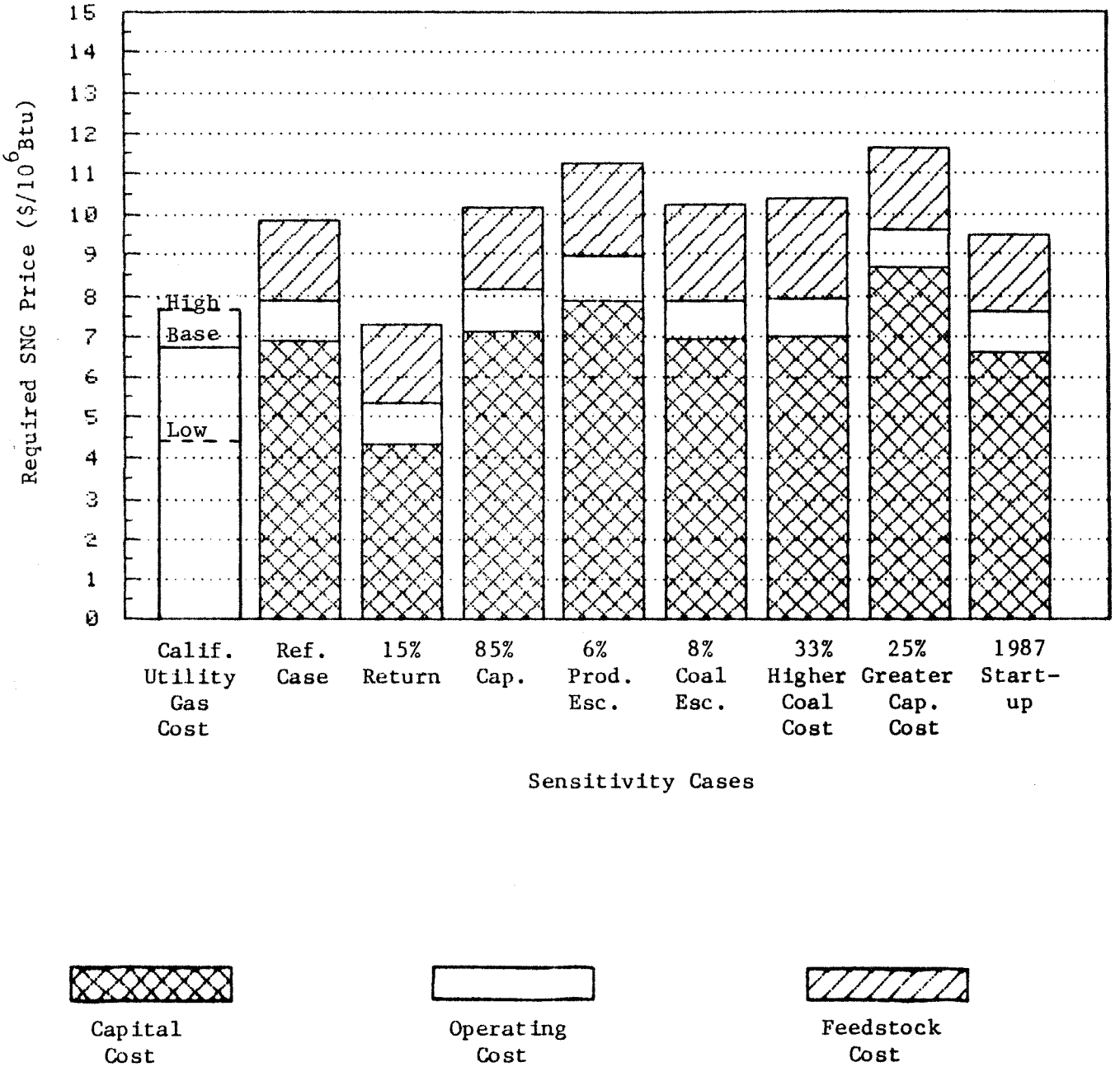


Figure 4-10. 1992 SNG PRODUCTION COSTS
LURGI TECHNOLOGY (1981 $)

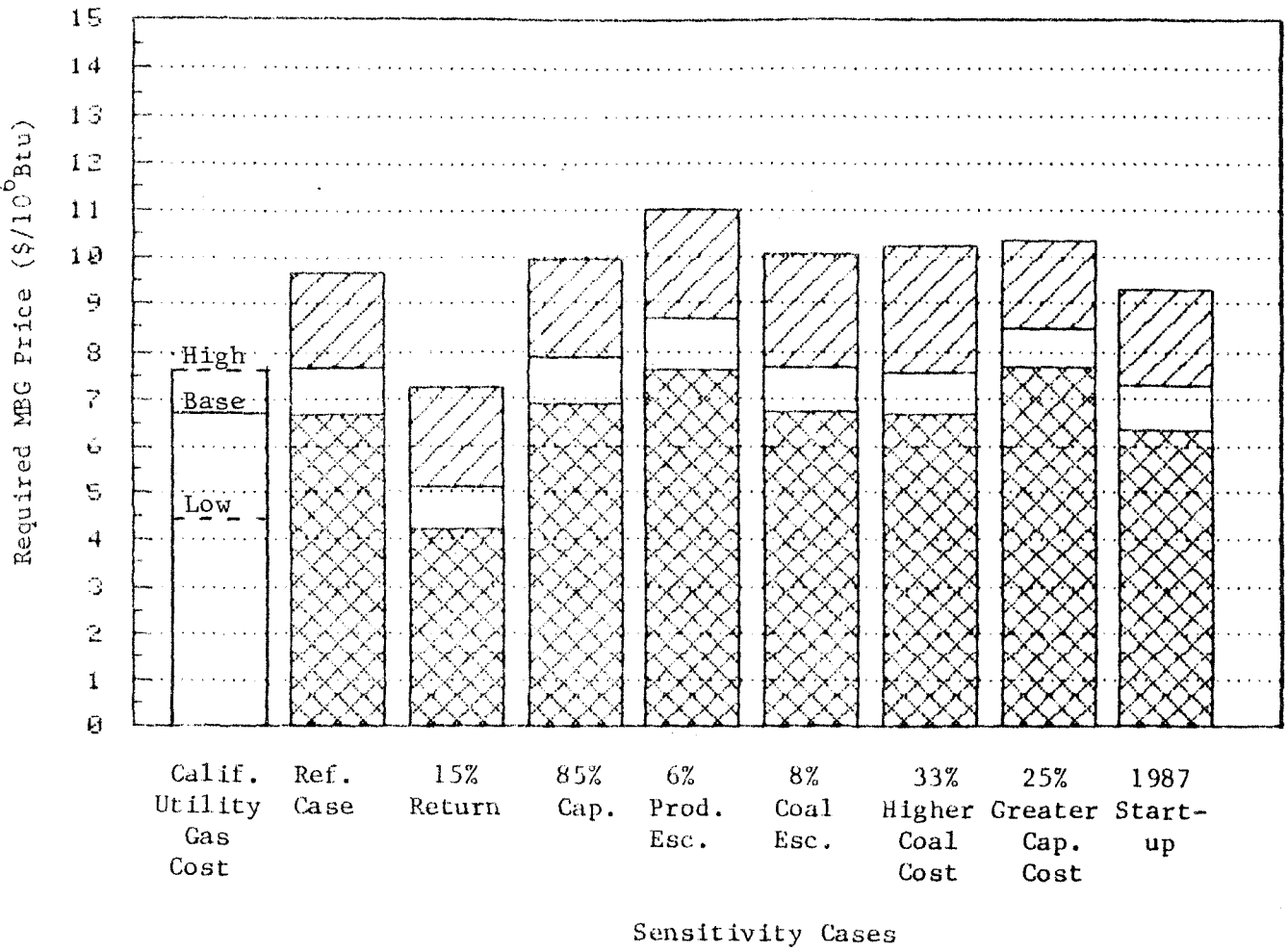


Figure 4-11. 1991 MEDIUM Btu GAS PRODUCTION COSTS (1981 $)

these systems potentially interesting in the 1992-1995 period; however, we do not expect significant activity in adding capacity of this type during the 1980s.

Other sensitivities are not particularly interesting since the projected costs are so high relative to expected natural gas costs. A measure of the risk in each plant, however, is provided by the 25 percent capital cost overrun sensitivity, which implies an increase in product cost of $\$1.66/10^6$Btu to $\$2.05/10^6$Btu in the three gasification cases. Thus, even with lower cost financing, the products could be uncompetitive if capital costs rise above the reference case levels.

3. Indirect Liquefaction

Synthesis gas produced in the gasification process described above can be further processed into higher valued products: methanol, M-gas or Fischer-Tropsch liquids. All of these products have the desirable property of being sulfur-free, since it must be removed from the synthesis gas prior to further processing. The methanol process has been described in detail in Section A. Thus, only the M-gas and Fischer-Tropsch processes are described in this section, although the methanol plant has been increased in scale to comparable levels with the Fischer-Tropsch plant.

In the M-gas process, crude methanol is vaporized in a reactor and passed through a catalyst where the methanol is converted to water and hydrocarbons. This reaction is highly exothermic and can be accomplished through different processes which include both fixed and fluid beds. The key aspect of the M-gas conversion is that the thermal efficiency of the process, although high (approximately 90 percent), still involves a loss to the heat content of the product. In addition, there is an increase in capital cost over a coal-to-methanol plant of approxiately 8 percent for costs associated with the M-gas process reactor. Thus, there is nearly an 18 percent increase in costs as measured in dollars per million Btu of product compared to methanol production. As will be discussed later, there is also a significant end-use efficiency loss compared against optimized neat methanol vehicles.

The Fischer-Tropsch process was developed first in the early 1920s. This process was used by Germany during the 1940s and is currently operating commercially in South Africa. As in methanol production, the Fischer-Tropsch process is "indirect" because first a synthesis gas is produced, then a catalytic process under pressure converts the synthesis gas to hydrocarbons. Two processes are currently in operation. The Lurgi ARGE process employs a fixed bed reactor and an iron catalyst, while the synthol process utilizes an entrained bed reactor. The primary difference between these processes is that the synthol technology produces relatively more light products and gasoline, while the ARGE process yields relatively more diesel fuel and heavy oils. The Fischer-Tropsch, M-gas and methanol processes are summarized in Table 4-21 at comparable scales.

The data for the methanol and M-gas plant costs in Table 4-21 were derived by scaling and adjusting the basic methanol plant data in Table 4-8, in order to preserve consistency of the cost estimates. A scaling factor of

Table 4-21. PLANT AND OPERATING COSTS FOR INDIRECT PROCESSES

	METHANOL[a] (TCGP)	M-GAS[b] (TCGP)	FISHER-TROPSCH[c]
PROCESS DESCRIPTION			
Coal Input (tpd)	28,735	28,735	28,735
Product Yield:			
Methanol (10^6gal/yr)	1,865	-	-
Gasoline (BPD)	-	62,250	29,418
LPG	-	-	3,121
Jet Fuel	-	-	6,336
Fuel Oil	-	-	9,503
Overall Thermal Efficiency	55%	50%	39%
10^9Btu input/day	665.2	665.2	665.2
10^9Btu output/day	365.9	327.0	261.2
CAPITAL REQUIREMENTS (millions 1981$)			
Erected Plant Cost[d]	$3,597	$4,053	$2,786
Other Owner Costs	1,037	1,169	804
TOTAL CAPITAL REQUIREMENTS	$4,634	$5,222	$3,590
1981 $/BOE	73,500	92,600	79,700
OPERATING COSTS (millions 1981$)			
Feedstock[e]	$173.0	$173.0	$173.0
O&M	182.6	191.3	157.3

a Derived from the 5000 tons-per-day Texaco/ICI plant cost shown in Table 4-8 and scaled up using a 0.84 scaling factor as shown in Table 4-10.

b Derived from the methanol plant cost estimates shown in Table 4-8 using the scaling factors shown in Table 4-10 and adjustment factors for capital costs of methanol conversion and efficiency losses supplied by Conoco and Chevron.

c Acurex: "Alternative Fuel Strategies for Stationary and Mobile Engines: Evaluation of Clean Coal Fuels." Volume III, July 1981
Fluor Corp., "A Fluor Perspective on Synthetic Liquids: Their Potential and Problems," 1979.
OTA, "Increased Automobile Fuel Efficiency and Synthetic Fuels." September 1982.

d Plant cost contingencies are assumed to be 15 percent for all three systems.

e $0.80/$10^6$Btu mine-mouth coal cost.

0.84 was used as discussed in Table 4-10 to scale the methanol plant up to approximately 19,000 tons-per-day. For the M-gas plant, a capital cost adjustment of 12.5 percent was used along with an efficiency loss of 10 percent to convert the coal-to-methanol plant costs to coal-to-methanol-to-gasoline.* As a check on this conversion, an independent estimate for M-gas was obtained from an ORNL study.** After adjusting for base year dollars to 1981 and western site location, the ORNL estimate for M-gas capital cost was approximately $81,200 per daily barrel of gasoline output, while the estimate derived indirectly from our methanol plant cost is $83,900 per daily barrel of gasoline output. This 3 percent difference is extremely minor given the uncertainty band surrounding the cost estimates in all these synfuel plants.

The Fischer-Tropsch plant costs were derived from three sources footnoted in Table 4-21, which imply that the range of expected capital requirements is from $65,000 to $81,000 per daily barrel of crude oil equivalent in 1981 dollars. The estimate used in Table 4-21 is consistent with an $80,000 per daily barrel capital cost and, thus, is on the more conservative end of the range.

The production cost results for these plants (Figures 4-12, 4-13, 4-14) illustrate some reasonably clear choices among systems. Fischer-Tropsch products appear to be extremely expensive versus M-gas, shale, or neat methanol as a transportation fuel. The system is too inefficient and produces a significant quantity of low-value products, making it less viable against the other synfuel options or conventional oil to gasoline. In effect, it is a commercial option which has been eclipsed by other alternatives for transportation fuels. As shown in Figure 4-12, the reference case assumptions imply a cost of about $95/bbl in terms of gasoline value equivalent,*** compared with a conventional baseline of $52.50 in 1992. Even lower cost financing of 15 percent return only lowers the cost to $70/bbl.

The relative sensitivities of the methanol production case have already been discussed thoroughly in Section A of this chapter. One change which must be noted is the effect of the scale increase on the reference case. Costs are projected at $0.77/gal which is reduced from the 5000 tpd plant of approximately $0.95/gal just on predicted scale economies.**** Although such improve-

---

*Suggested capital adjustment and efficiency loss given to JPL by discussions with technical staffs at Conoco and Chevron.

**"Liquefaction Technology Assessment - Phase 1: Indirect Liquefaction of Coal-To-Methanol and Gasoline Using Available Technology," ORNL - 5664, February 1981.

***For the Fischer-Tropsch process, the slate of products was converted into dollar values using the relative prices of gasoline, LPG, jet fuel and fuel oil and then the weighted value of all the products converted to gasoline equivalent value.

****The 5000 tpd plant production cost figure has been adjusted for mine-mouth coal costs of $0.80/$10^6$Btu.

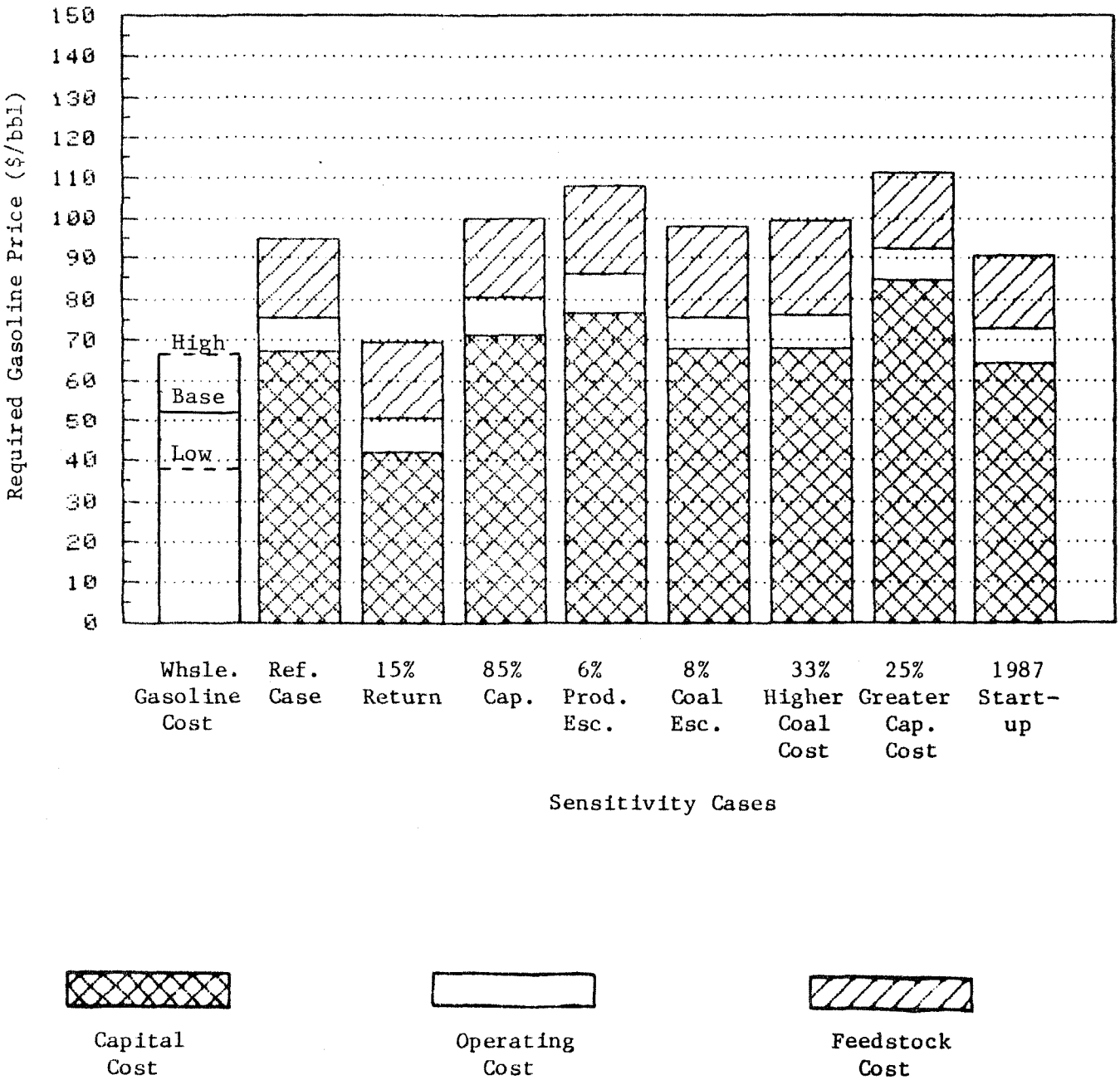


Figure 4-12. FISCHER-TROPSCH PRODUCTION COSTS
50,000 BPD GASOLINE EQUIVALENTS
(1981 $)

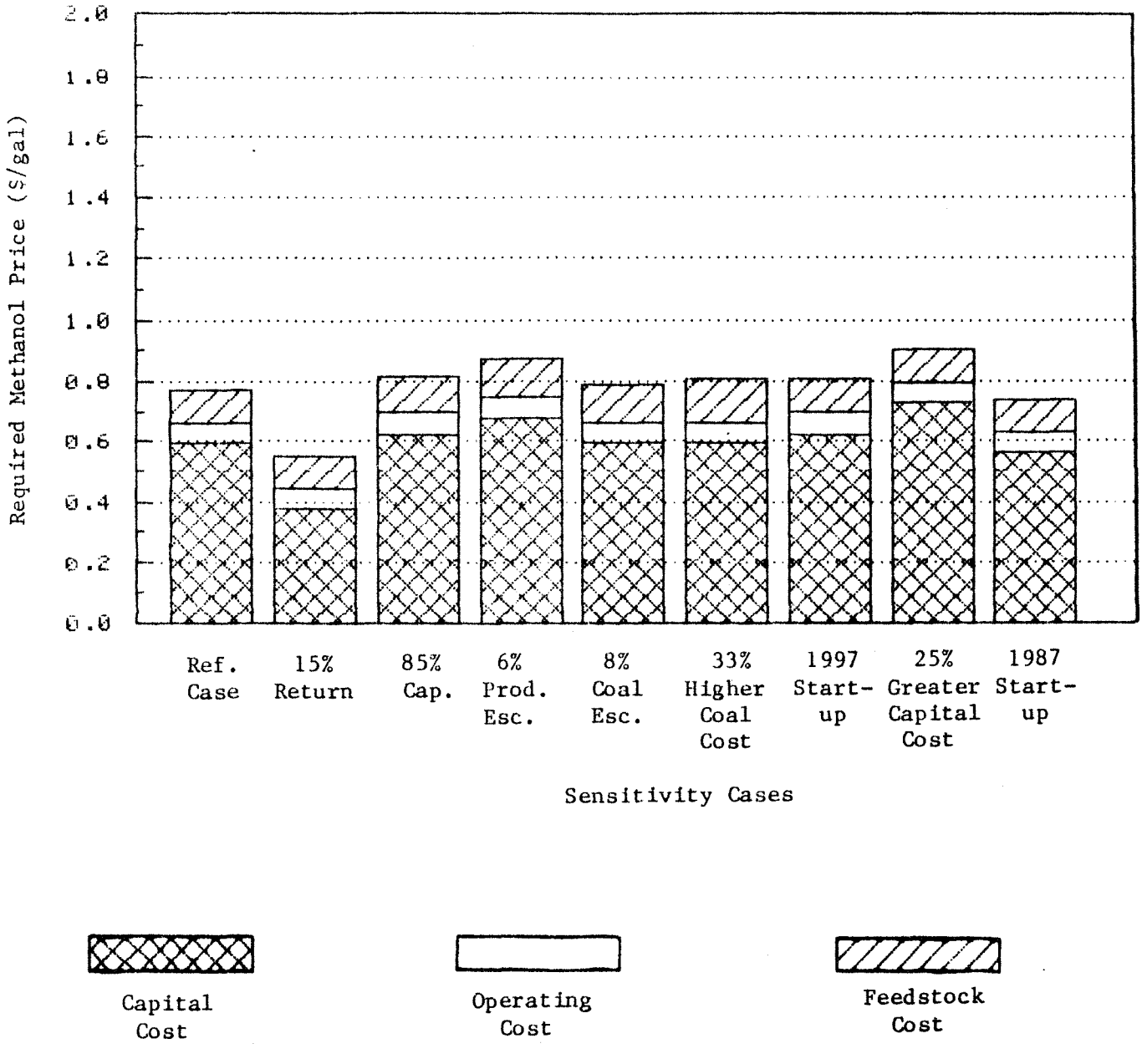


Figure 4-13. TCGP/ICI COAL TO METHANOL PRODUCTION COSTS 21,165 tpd (1981$)

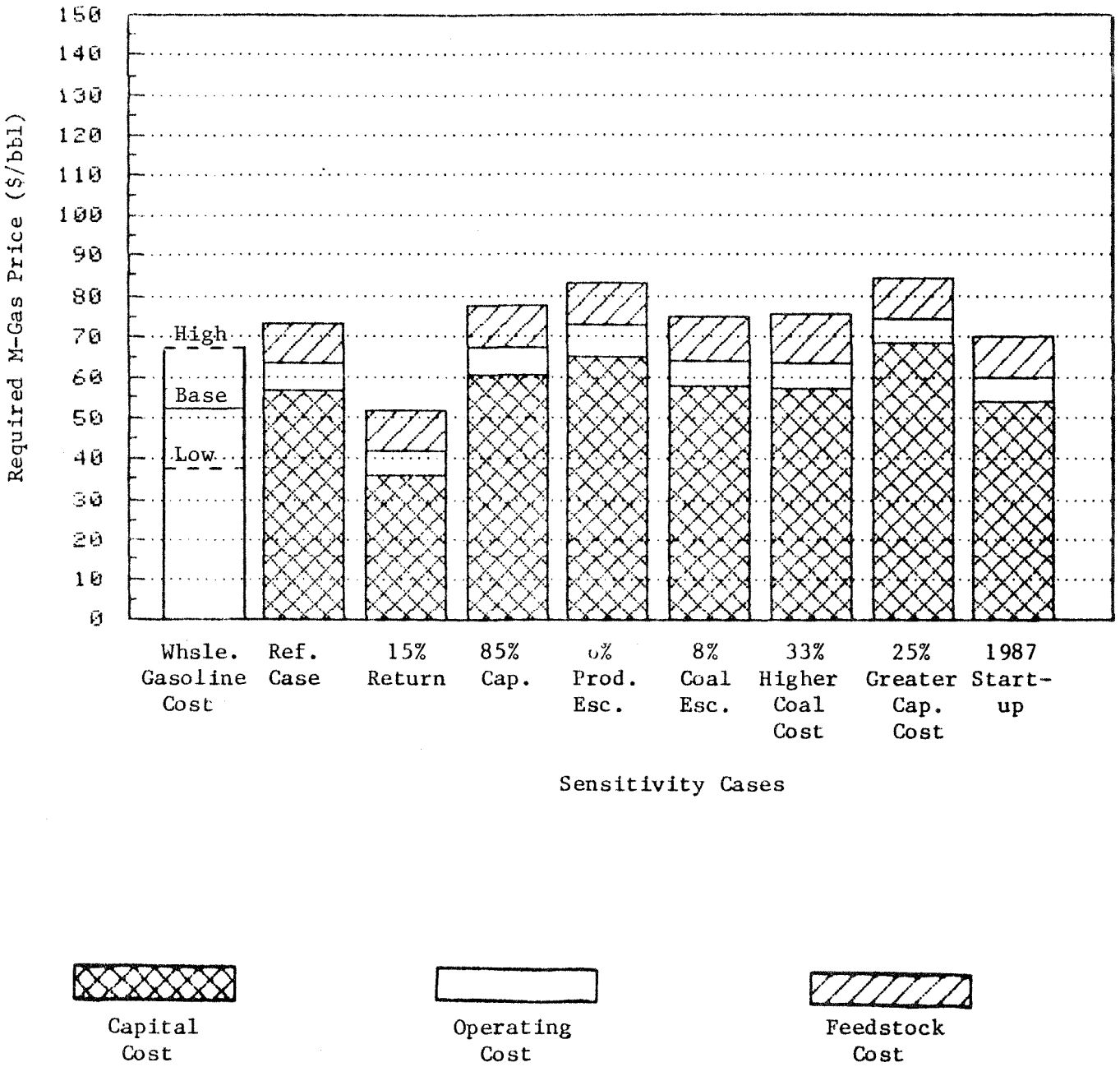


Figure 4-14. COAL TO METHANOL TO GASOLINE PRODUCTION COSTS 50,000 BPD (1981 $)

ments are somewhat speculative at this point and should be used with caution for the absolute value of the cost level,* it is appropriate for comparison with these other large-scale plants, which are also assumed to benefit from scale economies.**

The choice between M-gas and neat methanol becomes clearer when they are converted to either Btu equivalence or, even better, performance equivalence. This conversion has been performed in Table 4-22 for three cases: Btu equivalence, 1.7 fuel factor for neat methanol to gasoline and a 1.5 fuel factor for neat methanol to gasoline. These examples bound the realistic possibilities for neat methanol in comparison to gasoline or M-gas.

It is apparent from Table 4-22 that neat methanol, from a production viewpoint, is superior to M-gas as a potential competitor to conventional gasoline. There is a benefit in capital cost of production, higher conversion efficiency and end-use efficiency. The far right-hand column indicates that the end-use efficiency is a key factor in the long-run, as optimized neat methanol vehicles may become available. It is important to realize that the comparison above is not a prediction that neat methanol is viable versus gasoline in the 1992 time frame, rather that M-gas is not competitive on comparable terms and the relative economics of M-gas and neat methanol become more clearcut as utilization technology improves. Transportation costs and dealer mark-up would be higher per gallon of methanol and close this gap somewhat, but not enough to offset the overall advantage of neat methanol over M-gas.

Table 4-22. NEAT METHANOL VERSUS M-GAS REFERENCE CASE COMPARISON (1992 in 1981 $/gal)

	BTU EQUIVALENCE	1.7 FUEL FACTOR	1.5 FUEL FACTOR
Methanol	$ 1.57	$ 1.31	$1.16
M-Gas	1.74	1.74	1.74

*In looking at near and mid-term markets, the production costs from the 5000 tpd plant have been used. Methanol production costs based on the large plant in this section is only useful for comparative purposes.

**The methanol and M-gas plants were scaled using a 0.84 exponential scaling factor reflecting some economies in engineering, coal handling, utilities, and offsites.

4. More Advanced Synfuel Processes

There are other processes under development which could compete with those discussed above if they perform successfully at their targeted costs. Among these processes are a number of direct liquefaction technologies which share similar processing concepts. Generally, coal is slurried with a solvent and then heated and put under pressure in order to dissociate the coal structure. Coal liquids are subsequently separated from the remaining coal structure.*

Among those technologies which appear most promising are the solvent refined coal (SRC) system, the Exxon Donor Solvent (EDS) process, and the H-Coal process. The primary advantage of these systems is the potential for much higher efficiencies (e.g., 65% for SRC) than the indirect liquefaction technologies, which will lower costs for coal and coal handling. Pilot plants are scheduled for these processes in the 1980s which should improve our knowledge of their potential. For the near-term, however, it is our judgement that these systems are too experimental to enter significantly into the near-term transition analysis. Thus, we have not made cost projections of these plants because it is simply too early to judge their merit.

---

* Acurex Corp., Clean Coal Fuels, Volume III, p. 347.

D. PRODUCTION COST OVERVIEW

The decision to proceed with a large-scale capital investment is, of course, a highly complex process which involves a great deal of detailed analysis. While we cannot attempt to duplicate this process in this study, we have assembled a consistent set of data for comparison and applied a consistent economic methodology to provide a useful figure of merit. It must be realized, however, that the degree of uncertainty in some of the estimates which follow makes some of the perceived differences among them inconsequential. The discussion which follows will indicate where the data quality does not warrant making choices on processes or alternative systems which are overwhelmed by the uncertainty in the basic estimates. Particular attention will be devoted to looking for dominant choices where one system will be superior to others over a very wide range of dimensions and energy market conditions.

Production cost estimates in this chapter represent the full cost of supplying methanol from various feedstocks. By this definition of "cost" we mean the minimum revenue requirement. The basic approach is to derive an estimate of those costs incurred by a privately-owned company as a result of engineering, constructing, and operating and maintaining a methanol production facility. These costs, appropriately aggregated over the system lifetime and converted to a yearly basis, are divided by the expected annual methanol output of the specific system analyzed. The result is an estimate of the full cost per gallon of methanol from that production system: that is, if the system were to produce exactly its expected output and if that output was "sold" at a price equal to the "minimum revenue requirement," the resulting revenues would exactly recover the full costs of the system over its lifetime, including a return on the investments of stockholders and creditors.

The full costs referred to above include a compensation to investors for the opportunity cost of their committed funds, and thus the model is inherently a discounted cash flow approach. It differs from a conventional venture analysis, however, in that the revenue stream is derived rather than input. Required revenue per gallon (or million Btu) is found as the minimum energy price consistent with recovering all costs.

The minimum required revenue approach can be explained in terms of standard concepts from capital budgeting theory. First, the project represented by the methanol production system is constrained to have a net present value of zero. Alternately, the required revenue is defined as that which gives the methanol project an internal rate-of-return exactly equal to the opportunity cost or hurdle rate-of-return to the owning company.

The baseline assumption used in the study is a hurdle rate of 20% in nominal, after-tax (current dollar) terms on the entire project (i.e., 100% equity). This assumption was discussed at length with a number of the project sponsors and judged to be appropriate for the types of projects being analyzed in this study. While some firms may decide to leverage themselves at the corporate level, the major fuel producers in the U.S. are not likely to make specific project decisions on this basis. For the sake of making sensitivity analysis calculations, cases with 15% and 25% nominal returns have also been made. It is our view, however, that the industry would need to expect at least the 20% nominal after-tax return (approximately 15% real) on methanol plant investments to make the decision to proceed.

A graphical representation of the revenue requirements approach is shown in Figure 4-15. The cost of the project, represented by the "cost of capital" area, is the annual capital cost of the plant on both a per-unit product basis (left axis) and annual basis (right axis). Thus, all the construction costs, equipment costs, inventories, working capital requirements, contingencies, etc., have been present-valued and reduced to a constant annual equivalent, which provides for capital repayment and an assumed after-tax return. The variable costs grow over time as feedstock, material, labor, etc., escalate due to increased scarcity and general inflation.

One typical feature of capital intensive energy process plants is that once installed, their total production costs are less sensitive to changes in the general price level than non-capital intensive systems. Thus, even though the early production costs may tend to be higher than the competition (as depicted in Figure 4-15), they may be overtaken by more rapidly escalating fuel prices. Obviously, to make such investments on the expectation of making up for early losses in later years is a highly risky undertaking, as the recent drop in oil prices in 1982 illustrates. In a later section on near-term investment decisions in methanol production, the criteria for investments in methanol capacity expansion will be discussed in some detail.

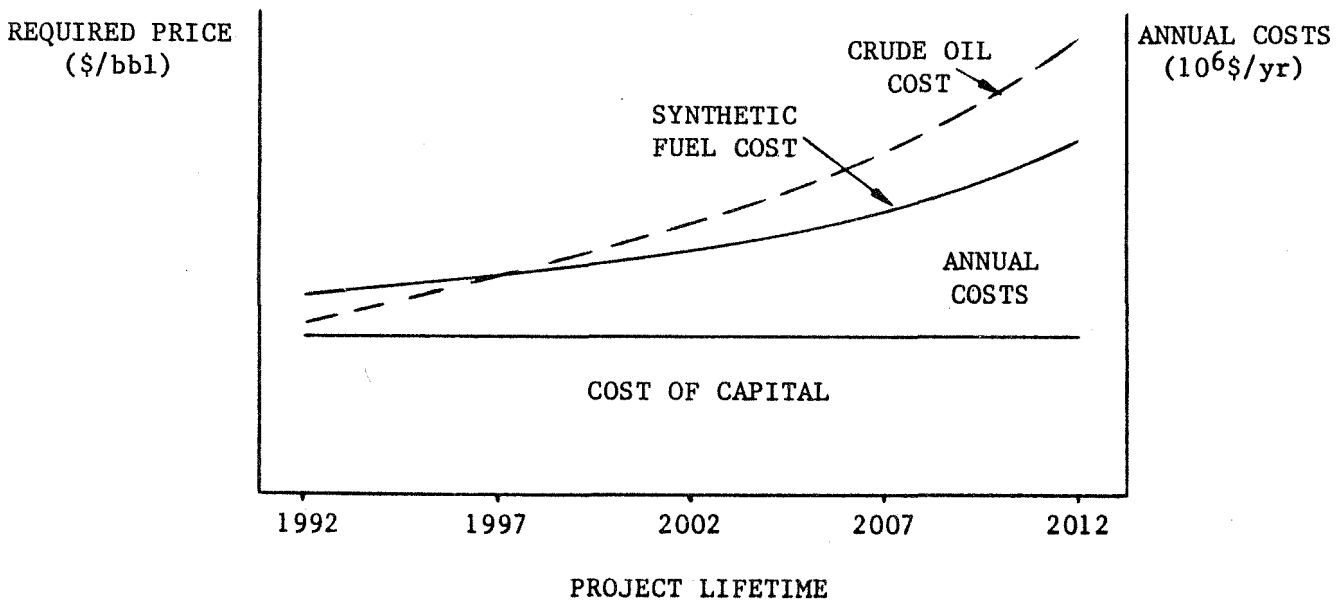


Figure 4-15. REQUIRED METHANOL PRICES
(nominal dollars)

In the results to follow, we will present a range of production cost information which involves many sensitivities on capital cost, fuel cost, escalation, required rates of return, year of operation and inflation. These sensitivities are important for two reasons. First, we want to understand and distinguish those cost drivers which are particularly important to methanol production cost. Second, many of the cases considered are particularly pertinent to a distinct phase of the development of the industry. For example, we have computed the impact of scale and required equity return on unit production costs. This information will be useful in characterizing the evolution of the industry where the earlier investments in coal-to-methanol capacity will be both smaller scale to gain experience and command a higher required return to compensate for scaling and market risks.

Thus, the material which follows is part of the raw material for our transition analysis on the industry production side, but does not lay out our production scenarios. The latter analysis is presented in the Summary Report in the section on methanol transitions (Section V). Obviously, required methanol prices in no way indicate that the value of the fuel in various uses is high enough to justify that price. The interaction of industry required prices and value of the fuel in various uses will determine its market value. In later sections we will also look explicitly at methanol value.

1. Captial Cost Summary

The detailed derivations of the capital and operating cost requirements are given in Sections B and C. This brief summary (Tables 4-23 & 4-24) is simply intended to present again in a concise fashion, the actual figures used in the required revenue calculations. It is important to note a few key facts about the methanol production plant specifications in Tables 4-23 & 4-24.

- Although the scales of some of the plants are different, it is our contention that the plants are appropriately scaled given the overall system configuration. For example, the collection and transportation of wood mitigates against large plant scale. In the case of natural gas, we are considering only remote barge-mounted synthesis plants, thus limiting potential scale. As a result, although some systems may appear to be at a disadvantage due to scale, this is not true when the end-to-end system is considered, which is done in another part of the report.

- Not all of the technologies in Tables 4-23 & 4-24 are at the same stage of development as of the writing of this report. We have adjusted for this inconsistency by assuming larger contingencies for processes in earlier stages of development. For example, since the Lurgi dry bottom gasification process is commercial, we have assumed a 15 percent capital cost contingency. Similarly, a low contingency is assumed for the barge-mounted methanol synthesis process (17%), but larger contingencies (20% and 25%, respectively) are assumed for the Lurgi slagger and shale retort, since they are in earlier stages of development. In addition, in our transition analysis, we have also assumed that these processes are implemented in time frames consistent with development through pilot plants,

Table 4-23. METHANOL PRODUCTION AND OPERATING COST SUMMARY

PROCESS TECHNOLOGY	LURGI DRY BOTTOM	TEXACO ICI	TEXACO ICI	TEXACO ICI	LURGI ICI	TEXACO ICI (Refinery Site)	ICI	WINKLER ICI
FEEDSTOCK tpd input	coal 8,563	coal 6,788	coal 13,576	coal 28,735	wood 1,000	coke 3,100	natural gas	coal 17,171
METHANOL OUTPUT (tpd)	2,425	5,000	10,000	18,744	575	2,000	3,000	5,000
BY-PRODUCT OUTPUT (tpd)								
MBG (10^9Btu/day)	59.4	-	-	-	-	-	-	-
Sulfur (tpd)	40	26	52	97	-	-	-	-
OPERATING FACTOR	.90	.90	.90	.90	.90	.90	.90	.90
EFFICIENCY (%)	63	55	55	55	55	55	63	.40
SYSTEM LIFE (years)	20	20	20	20	20	20	20	20
TOTAL CAPITAL INVESTMENT (millions 1981$)	1,204.2	1,534.2	2,740.9	4,634.1	184.4	542.6	449.0	1,642.3
CAPITAL COSTS/ANNUAL GALLON METHANOL (1981$/gal)	2.88	3.09	2.75	2.48	3.22	2.73	1.52	3.31
NET OPERATIONS & MAINT. (millions 1981$)	44.4	84.3	133.2	182.6	19.9	54.4	42.2	75.4
FEEDSTOCK COSTS* (millions 1981$)	107.5	78.4	156.8	293.9	10.6	55.2	33.6	84.9

*Feedstocks are given for coal at $1.80/$10^6$Btu, petroleum coke at $1.80/$10^6$Btu, and remote natural gas at $1.00/$10^6$Btu all delivered to the plant.

Table 4-24. SYNFUEL PRODUCTION AND OPERATING COST SUMMARY

PRODUCTION TECHNOLOGY	SYSTEM				
	SHALE SURFACE RETORT	SNG LURGI	MBG LURGI	M-GAS	FISCHER-TROPSCH
Coal Input (tpd)	-	22,175	21,530	28,735	28,735
Product Output (BPDOE)	50,000	250 10^9 Btu	250 10^9Btu	56,380	50,000
Operating Factor	.90	.90	.90	.90	.90
Efficiency (%)	-	.57	.65	.50	.40
Lifetime (years)	20	20	20	20	20
Total Plant Investment (millions 1981$)	$2,834	$2,034	$1,771	$4,053	$2,786
Other Capital Costs* (millions 1981$)	$ 594	$ 575	$ 501	$1,169	$ 804
Operations and Maintenance** (millions 1981$)	$ 273	$128.6	$124.6	$191.3	$152.3
Feedstock Costs *** (millions 1981$)	-	$181.8	$177.6	$237.8	$237.8

* Includes start-up, land, working capital, initial inventories, personnel training, owner engineering and administration.

** Operations and maintenance costs include operating and supervisory labor, G&A, operating supplied, power, water, maintenance, insurance and state and local taxes.

*** Feedstock costs are based on coal to the plant gate at $\$1.10/10^6$ Btu. Other sensitivities have been run for both $\$0.80/10^6$ Btu and $\$1.40/10^6$ Btu.

demonstratons and finally commercial-scale systems. Not all these systems are candidates for full-scale commercial production in the late eighties.

- o Finally, we have attempted to explicitly acknowledge the uncertainty of the costs for all these systems compared to conventional fuels by doing sensitivities on various aspects of the process assumptions and examining the impact on production costs. These results are presented at the end of this chapter.

2. Financial Assumptions

The economic methodology used in this study requires that assumptions be made for the following financial parameters: general inflation rate; escalation rates for capital equipment, operations and maintenance expenses and feedstock costs; debt-equity ratio; before-tax interest rate on debt; required after-tax return on equity; appropriate local, state, and federal tax rates; system lifetime; and depreciation method. Each of these parameters will be discussed below, and are summarized in Table 4-25.

Table 4-25. ECONOMIC ASSUMPTIONS SUMMARY

DESCRIPTION	ASSUMED VALUES	
	1982 - 1990	1990 - 2000
General Inflation Rate	7.0%	6.0%
Construction Escalation Rate	8.0%	7.0%
Operations & Maintenance Esc. Rate	7.0%	6.0%
Return-to-Equity (nominal after-tax)	15%, 20%, 25%	15%, 20%
Interest Rates on Debt (before-tax)	14%	12%
Debt/Equity Ratio*	0/100	0/100
Depreciation Schedules:		
Plant and Equipment	ACRS - 5 yrs	ACRS - 5 yrs
Buildings	ACRS - 10 yrs	ACRS - 10 yrs
Federal Income Tax Rate	46%	46%
State Income Tax Rate	9%	9%
Investment Tax Credit	10%	10%
Insurance and Other Taxes	2%	2%

* The debt/equity assumption is really more general than indicated in Table 4-25. A 15 percent nominal after-tax return, for example is the same cost requirement as a 25 percent equity return, a 16 percent interest rate and a 70/30 debt equity ratio. Thus, our results are consistent with a variety of financing options, which are summarized in Table 4-28.

a. Inflation Rate. The general inflation rate is assumed to be 7 percent from 1981 to 1990 and 6 percent from 1991 to 2000.* These rates correspond to the GNP price deflator taken from DRI's Spring 1982 Energy Review** and are consistent with the other escalation rates utilized in this study. Obviously, this rate has been rapidly changing over the last decade and could deviate substantially from this assumed level. Since a change in the GNP deflator is implicitly included in both our escalation factors and discount factors, much of this variability would cancel out.

b. Escalation Rates for Capital, Variable Costs and Feedstock Costs. Capital costs were assumed to escalate at 8 percent throughout the construction period up to 1989 and at 7 percent thereafter in nominal terms or 1.0 percent in real terms. Operations and maintenance costs were assumed to escalate at 7 percent for the entire forecast period. Thus, we have assumed that the recent pattern of real escalation in these factors continues.

Feedstock costs were assumed to escalate at different rates depending upon the feedstock in question. Table 4-26 summarizes the assumptions used for all methanol production feedstocks. A more thorough description of the energy forecast assumptions may be found in Section III of the Summary Report.

c. Debt-Equity, Cost of Debt, Return on Equity. Projects of the size and scope envisioned in this report can be financed in a variety of ways. The base case assumption is that the viability of the project should be based on a hurdle rate which is assumed to be 100 percent equity financing with either 15, 20, or 25 percent after-tax return-to-equity. In addition to this base case, a number of other sensitivities will be considered to illustrate the impact on product cost of financing alternatives. In Table 4-27 the financing sensitivities considered have been summarized. The choice of the appropriate financing structure and required return for a given project will depend on the overall economic climate prevailing at the time the decision to proceed is made, the status of the technology process used, the availability of governmental incentive programs, etc. These considerations will determine the assumptions used in our transition analysis. This section of the report is merely explaining how the production cost projections were made, not the rationale for them.

d. Tax Rates, Tax Credit. The combined (state and federal) effective income tax rate is 51 percent. This composite rate was computed according to the equation:

$$\text{Combined effective tax rate} = \text{federal tax rate} + \text{state tax rate} - (\text{federal tax rate} \times \text{state tax rate})$$

*Actually the rates in DRI were 7.1 percent and 5.9 percent which were rounded off for simplicity.

**Data Resources, Inc., Energy Review Spring 1982, Volume 5, Number 5, 1982.

Table 4-26. FEEDSTOCK COSTS* (1981 $/million Btu)

FEEDSTOCK	COSTS (at plant)		ESCALATION RATES	
	BASE CASE	SENSITIVITIES	1981-1990 (%)	1991-2000 (%)
Natural Gas	$1.00	$1.50 2.00	9.0	8.0
Petroleum Coke	$1.80	$1.20 $2.40	9.0	8.0
Wood Waste	$1.80	$2.40	7.0	6.0
Coal**	$1.10	$0.80 $1.40	8.0	7.0

* Data Resources, Inc., Energy Review Spring 1982, Volume 5, Number 5, 1982.

** As a means to get appropriate coal prices for use in the base case and sensitivity analysis we have obtained direct price quotations from the coal fields under study: Black Mesa, Southern Utah, San Juan, Vinta, Green River and Powder River. The figures in Table 4-26 bound the pertinent range for coal costs in these areas.

where the federal tax rate is 46 percent and the state tax rate is assumed to be 9 percent. The investment tax credit used in the cost calculations is 10 percent.

e. System Lifetime and Plant Capacity Factor. System lifetime for all the plants was assumed to be 20 years and the plant was assumed to operate 330 days per year.

f. Depreciation Method. Allowable percentages in the Economic Recovery Tax Act of 1981 were used. Ninety-five percent of the plant was assumed to be 5-year depreciable, and 5 percent of the plant was assumed to be 10-year depreciable. Because in all cases, the plants would come on line after 1986, depreciation rates were used as shown in Table 4-28.

Table 4-27. FINANCING ASSUMPTIONS

FINANCING OPTION	NOMINAL AFTER-TAX RETURN ON EQUITY (%)	BEFORE-TAX DEBT RATE (%)	DEBT/EQUITY RATIO
REFERENCE CASE	20.0	-	0/100
Sensitivity 1	15.0	-	0/100
Sensitivity 2	25.0	-	0/100
Sensitivity 3	13.5	-	0/100
Sensitivity 4	11.0	-	0/100
EQUIVALENT CASES	15.0	-	0/100
to our 15% nominal	18.5	.14	30/70
after-tax case	34.0	.14	70/30
EQUIVALENT CASES	20.0	-	0/100
to our 20% nominal	25.6	.14	30/70
after-tax case	50.7	.14	70/30
EQUIVALENT CASES	13.5	-	0/100
to our 13.5% nominal	28.6	.14	30/70
after-tax case	16.3	.14	70/30
EQUIVALENT CASES	11.0	-	0/100
to our 11% nominal	12.7	.14	30/70
after-tax case	20.3	.14	70/30

Table 4-28. DEPRECIATION SCHEDULES

TEN-YEAR DEPRECIABLE CAPITAL		FIVE-YEAR DEPRECIABLE CAPITAL	
Year	Rate	Year	Rate
1	.10	1	.20
2	.18	2	.32
3	.16	3	.24
4	.14	4	.16
5	.12	5	.12
6	.10		
7	.08		
8	.06		
9	.04		
10	.02		

3. Methanol Production Costs

A cost comparison of all the methanol plants described in Table 4-23 under the reference scenario assumptions of Table 4-29 is shown in Figure 4-16. These are all plant-gate costs and thus should not necessarily be considered as indicating preferred options until end-to-end systems are compared.

On a plant gate basis, however, it is clear that remote natural gas is the least expensive method for producing methanol in the short-run under the reference scenerio assumptions of Table 4-29 and the sensitivities which have been run for the various systems. Even if remote gas feedstocks were to cost $\$2.50/10^6$Btu, it would have a decisive edge over the alternatives. The implications of results are discussed in the report summary and the transition analysis section of this chapter. One feature which is consistent throughout all our sensitivities is that the capitalization of the project (equity share and the return-to-equity) are the cost drivers on the production side. A second important factor is the expected annual increase in the methanol product price. If it is anticipated that it will grow at the expected rate of inflation (6%), then the minimum acceptable selling price is significantly higher than if it is expected to grow at 2 percent above general inflation (8% nominal). Methanol production costs are particularly insensitive to feedstock costs and moderate changes in plant scale. For reference purposes, the production cost results are shown in Table 4-30 for the methanol cases, and in Table 4-31 for the alternative synfuel cases.

4. Other Production Alternatives

Although they do not fit into the previous sections of the report, two production cost issues which are pertinent to our transition analysis are LNG and Gulf Coast methanol production. The former is important because it will determine the value of remote natural gas as an alternative to methanol production and the latter is a market which could attract methanol from remote natural gas away from fuel markets.

Table 4-29. REFERENCE CASE ASSUMPTIONS

Year of Commercial Operation	1992
System Life (years)	20
Discount Rate (nominal, after-tax)	20%
Investment Tax Credit	10%
Composite Income Tax Rate	51%
Insurance and Other Taxes	2%
Ten-Year Depreciation Factor	5%
Five-Year Depreciation Factor	95%

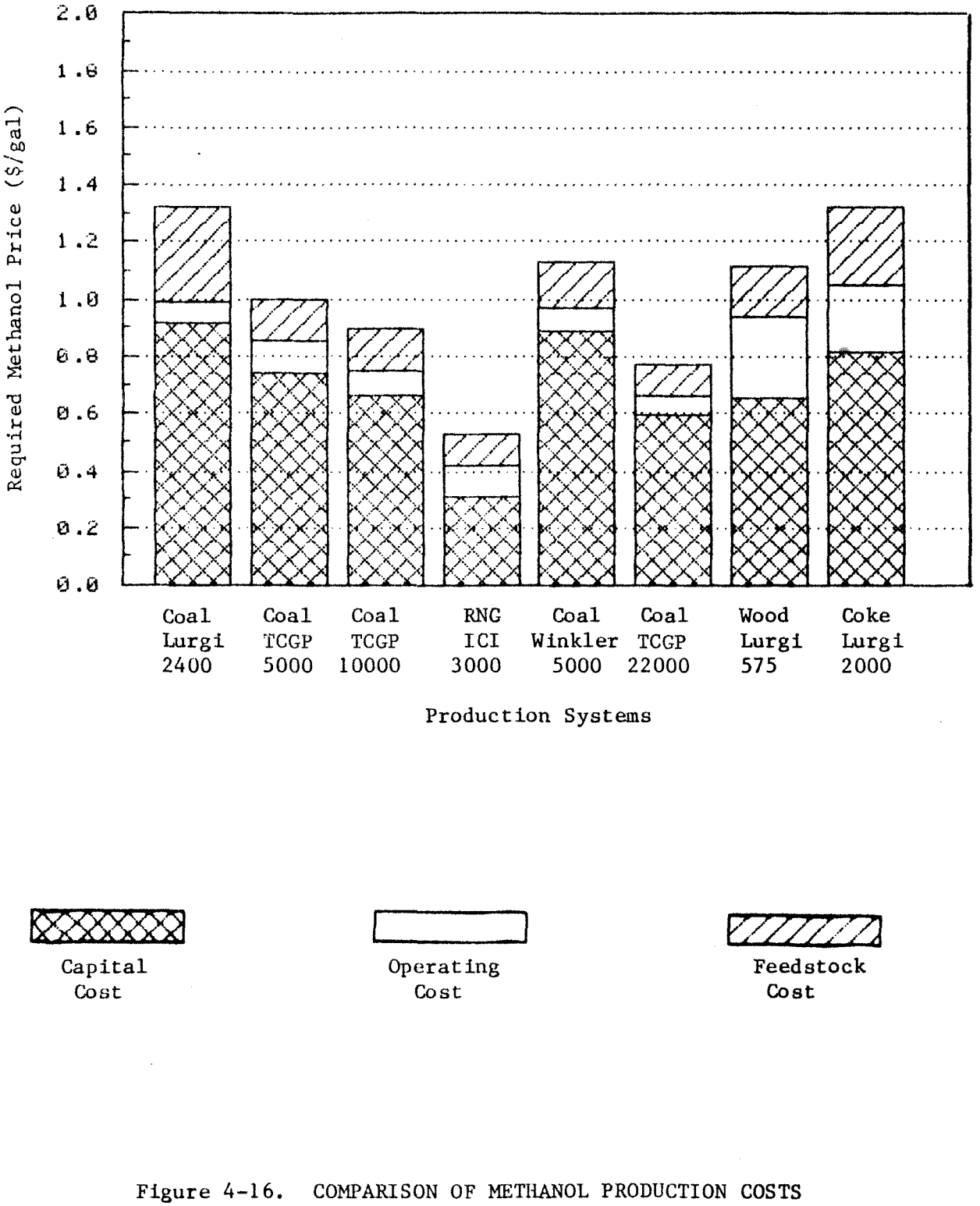


Figure 4-16. COMPARISON OF METHANOL PRODUCTION COSTS FROM ALTERNATE FEEDSTOCKS (Reference Case - 1981 $)

Table 4-30. METHANOL PRODUCTION COST SUMMARY
(1981 $/gal)

SENSITIVITY	LURGI D.B. 4,000	TCGP 5,000	TCGP 10,000	TCGP 18,744	WOOD 575	PETROLEUM COKE 2000		GULF COAST 3,000	RNG 3,000	ALASKAN COAL 5,000
						GRASS ROOTS	REFINERY SITE			
Reference Case	1.32	1.00	0.90	0.77	1.12	1.32	1.07	0.71	0.53	1.13
15% Return	0.98	0.73	0.65	0.55	0.89	1.01	0.86	0.69	0.42	0.80
25% Return	1.76	1.36	-	-	-	-	1.37	-	0.66	1.56
85% Capacity	1.40	1.06	0.95	0.81	1.19	1.39	1.26	0.79	0.56	1.20
6% Product ESC	1.50	1.14	1.02	0.87	1.27	1.50	1.22	0.80	0.60	1.29
8% Feedstock ESC	1.38	1.03	0.92	0.79	1.15	1.27	1.12	0.78	0.55	1.16
Feedstock 33% Higher	1.42	1.05	0.95	0.81	1.18	1.41	1.16	0.83	0.58	1.19
25% Cap. Cost Increase	1.53	1.17	1.05	0.90	1.27	1.51	1.22	-	0.60	1.34
1987 Start-up	1.27	0.96	0.86	0.74	1.08	1.27	1.03	0.67	0.51	1.09
1997 Start-up	-	-	0.94	0.81	-	-	-	-	-	-
Feedstock 33% Less	-	0.95	0.85	-	-	-	0.99	-	-	-
Feedstock 50% Higher	-	-	-	-	-	-	-	-	0.58	-
Feedstock 66% Higher	-	-	-	0.86	-	-	-	-	-	-
Feedstock 100% Higher	-	-	-	-	-	-	-	-	0.64	-
13.5% Return	-	0.65	-	-	-	-	-	-	-	-
11.0% Return	-	0.56	-	-	-	-	-	-	-	-
25 Year Lifetime	-	0.94	-	-	-	-	-	-	-	-
30 Year Lifetime	-	0.91	-	-	-	-	-	-	-	-
Returns to Scale (= .7)	-	-	0.83	0.65	-	-	-	-	-	-

Table 4-31. PLANTGATE SYNFUEL PRODUCTION COST SUMMARY (1981 $)

SENSITIVITY	SHALE PLANT	SNG LURGI DB	SNG LURGI SLAGGER	MBG PLANT	M-GAS	FISCHER-TROPSCH	LNG PLANT
Reference Case	61.74	11.47	9.85	9.66	73.00	94.50	4.84
15% Return	44.52	8.40	7.28	7.19	51.80	69.60	3.79
85% Capacity	65.52	11.83	10.15	9.96	77.30	100.15	5.47
6% Product ESC	70.56	13.07	11.22	11.00	83.18	107.69	5.58
33% Lower Feed Cost	-	11.86	10.21	10.04	74.79	98.00	5.16
33% Higher Feed Cost	-	10.89	9.31	9.09	70.34	89.32	-
1997 Start-up	-	12.05	10.39	10.22	75.66	99.71	5.37
25% Greater Cap. Cost	74.82	13.53	11.58	11.32	84.10	111.31	5.68
1987 Start-up	-	11.01	9.46	9.28	69.98	90.94	4.74
35% Higher O&M	63.67	-	-	-	-	-	-
66% Higher Feed Cost	-	-	-	-	-	-	5.89
UNITS	$/bbl Oil	$/$10^6$ Btu	$/$10^6$ Btu	$/$10^6$ Btu	$/bbl Gasoline Equiv.	$/bbl Gasoline Equiv.	$/$10^6$ Btu

In the case of LNG, a set of four plant cost estimates* were used to derive a composite LNG plant cost estimate shown in Table 4-32. The results of running the assumptions in Table 4-32 in the financial model are shown in Figure 4-17 and do not yet include transportation costs. Under the reference case assumptions, the production costs are $4.84/$10^6$Btu, while at a 15 percent return the costs fall to $3.79/$10^6$Btu. Adding regasification at the destination point adds approximately $0.75/$10^6$Btu to all the LNG costs in Table 4-32.

The second production case involves the situation for existing Gulf Coast methanol producers who will have their gas contracts expire in the mid 1980s and be forced to either produce on market gas or cease operations.**

* Obtained from Conoco data which included estimates by Mitsui, Nissho Iwai, Sumitomo and Conoco.

** The specific assumptions used were that capital expenditures would be $39 million for working capital, O&M would be $29.9 million annually, natural gas would be $159.4 million at $4.75/$10^6$Btu, and plant output would be 296 million gallons-per-year.

Table 4-32. LNG PLANT AND OPERATING COSTS (10^6 1981 $)

SYSTEM OUTPUT (M^3 day)	2800
CAPITAL COSTS	
Plant Investment	$345.5
Other Owner Costs	32.9
OPERATING COSTS	$ 18.0
FEEDSTOCK COSTS*	$ 23.9

*Feedstock Cost assumed $1.00/$10^6$Btu in baseline case.

The question of interest is whether they can compete assuming that the plant cost is sunk and market gas will cost somewhere between $4.50/$10^6$Btu and $5.00/$10^6$Btu in 1987. Our results shown in Figure 4-18 show that under the reference assumptions and a $4.75/$10^6$Btu market gas cost with no capital charges other than for working capital, the methanol production cost would be $0.67/gal. Other sensitivities on this option change the results slightly to the $0.70 to $0.75/gal range. This range of prices for the existing U.S. producers has some interesting implications for the transition analysis discussed in the next section.

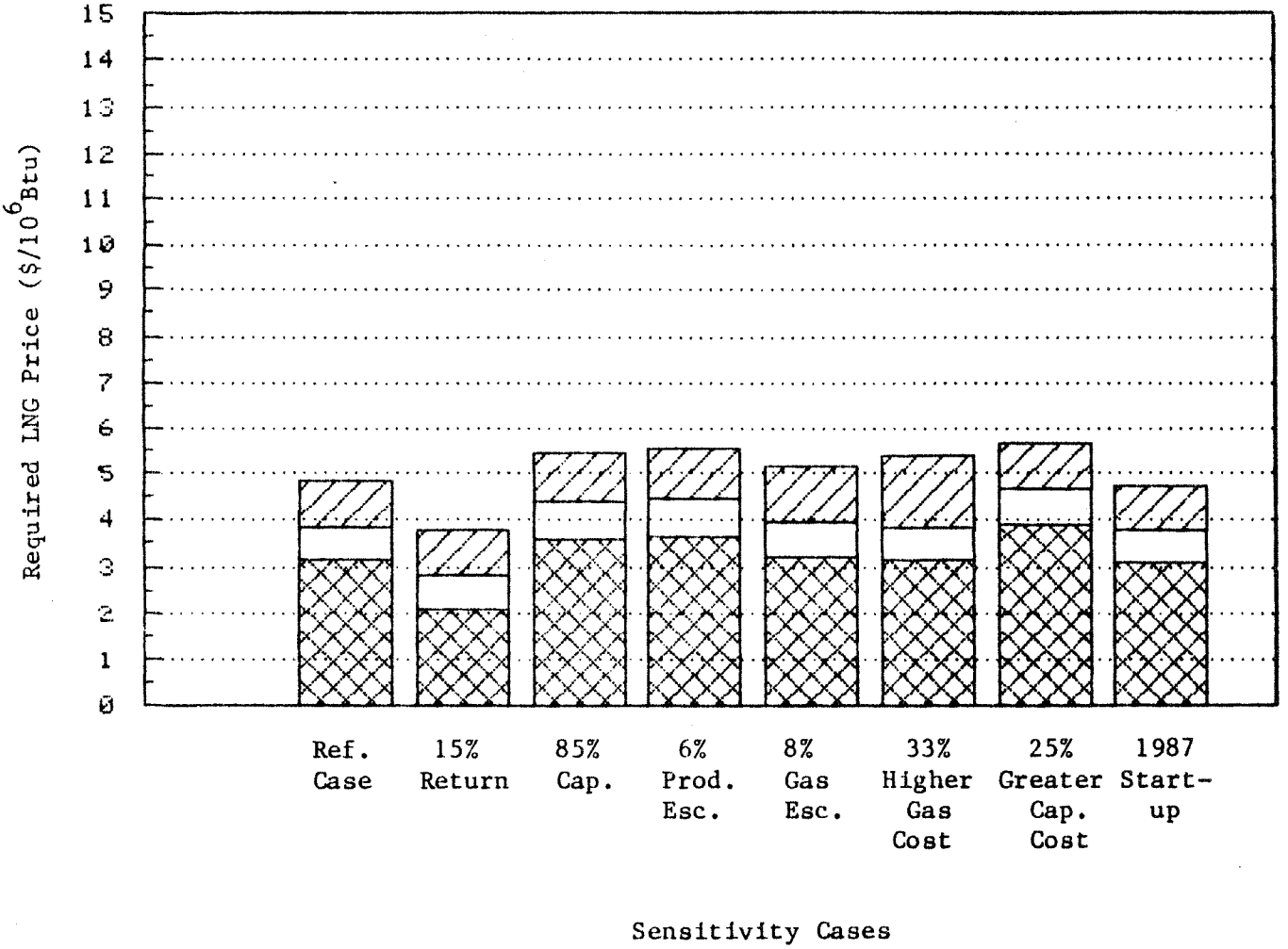


Figure 4-17. 1992 LNG PRODUCTION COSTS FROM REMOTE NATURAL GAS ON BARGE-MOUNTED PLANTS (1981 $)

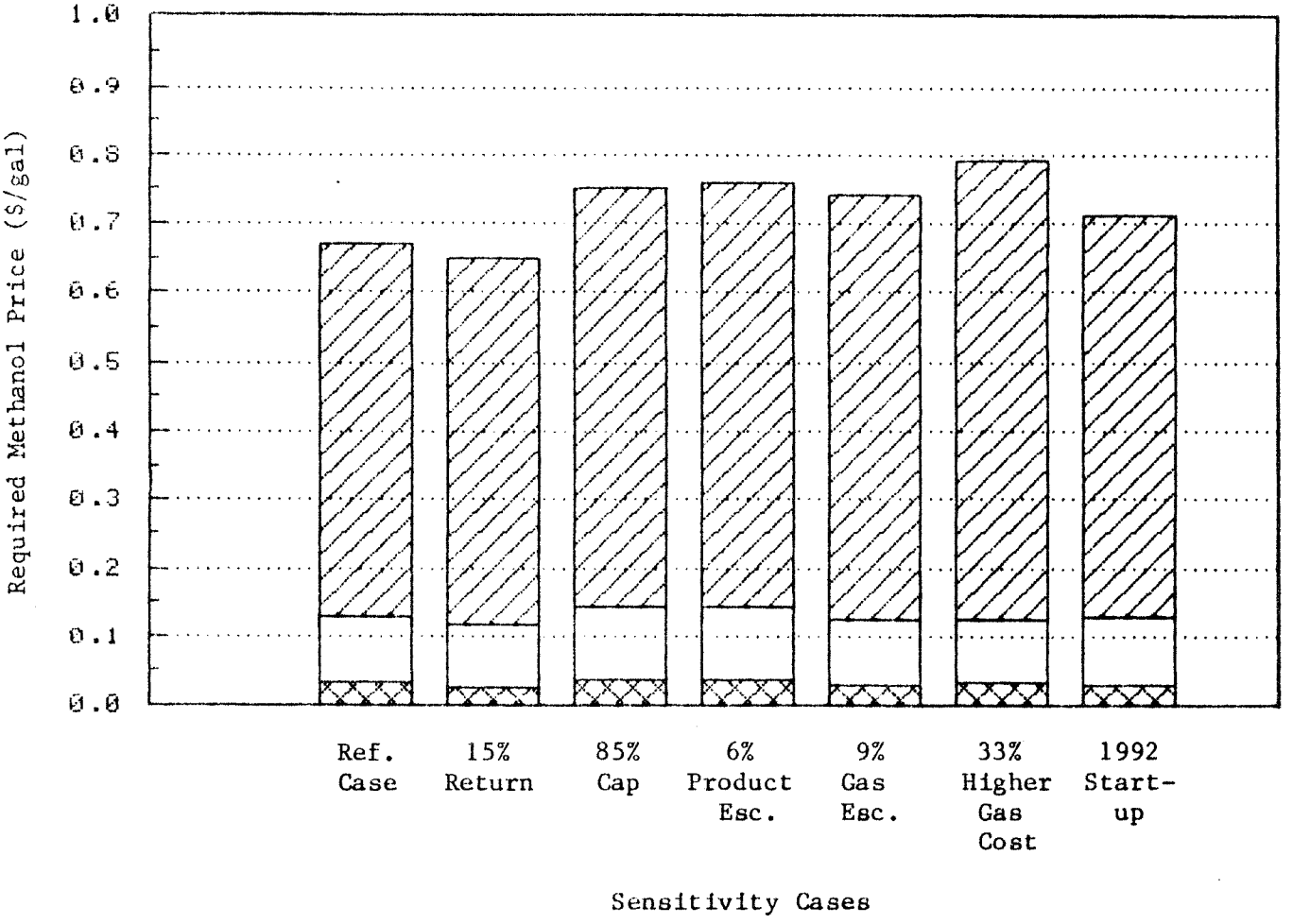


Figure 4-18. 1987 GULF COAST NATURAL GAS-TO-METHANOL PRODUCTION COSTS IN EXISTING PLANTS (1981 $)

E. TRANSITION PERIOD PRODUCTION OPTIONS

As one examines realistic options for methanol production in the late eighties and early nineties, the factors which seem most critical are: the future of the remote natural gas production, the role of the Synthetic Fuels Corporation in stimulating methanol fuel production, and the question of whether there will be a Western coal-to-methanol plant in this century. Each of these points will be discussed below as part of our analysis of transition paths.

1. Near Term (1985 - 1987)

The most significant question regarding methanol in this near-term period is the future of the existing U.S. methanol production capacity. In order to evaluate this issue we made some projections of production costs for existing plants in the 1985-87 time frame under the assumptions that the producer would be operating on market gas* and that the plant cost is sunk.

It is our understanding from industry sources that the existing natural gas contracts for U.S. producers will virtually all be expired in the 1984-86 period. Thus, as deregulation occurs these producers will have to purchase market gas if they wish to remain in production. By 1985, the residual oil price is forecast to be $\$4.50/10^6$Btu in constant 1981 dollars, thus, natural gas for industrial users will be very close to this price, assuming that the long-run equilibrium price for natural gas is parity with residual oil at the end-use point.

Even with capital costs assumed to be sunk (except for a small investment in working capital), the minimum production cost for such a producer would be $0.67/gal in 1981 dollars at the plant gate in 1987. Although this operating cost is high by current standards, it is still sufficiently low to keep existing producers in the market. Obviously, this conjecture is only valid for existing plants, which justifies the assumption of sunk capital costs. It would not be expected that any additional U.S. capacity based on non-remote gas be built in the future.

Four factors are crucial in the expected continued viability of the U.S. industry. First, expectations of oil prices and hence natural gas prices have moderated considerably in the last year. Whereas crude oil price forecasts of $45/bbl in 1981 dollars for 1985 were common** a couple of years ago, now they are expected to be only $33/bbl.*** As a result, the market gas forecast in the same terms has fallen from $5.50 to $4.50 per 10^6Btu. A second factor which helps maintain the viability of the existing industry is the high cost of capital in both the U.S. and around the world. Existing producers with

---

* Market gas simply means that it commands the market value of U.S. natural gas which is presumed to be parity with mid-sulfur residual oil.

** For example, see DRI Energy Forecast, Autumn, 1980.

*** See DRI Energy Forecast, Spring 1982.

amortized plants are somewhat shielded from entry by the high cost of new capacity. A third factor is that transportation costs to the Gulf Coast area are expensive for production based on remote natural gas in Alaska, Indonesia, or Saudi Arabia. These tanker costs would be over ten cents per gallon from either Alaska or Indonesia. The final factor favoring continued U.S. market gas-based methanol production is the import duty of 18 percent on imported chemical market methanol. At a projected market value of chemical grade methanol of $0.74/gal, the duty alone would add $0.12 to the cost of each gallon.

The pattern which emerges therefore is that the existing "market gas" to methanol producers will represent the marginal producer in the chemical market during the mid to late 1980s. Thus, there may be some producers who have lower costs including transport* than the existing U.S. mainland producers, but they will not have the capacity to satisfy the demand, and will earn high returns. The fuel market as it evolves, however, is a very different case. First, there is no duty on methanol used as a fuel which is a significant savings and, second, the transport cost to West Coast ports is less than to the Gulf Coast from Alaska and Indonesia. The potential producers from coal, remote natural gas, and other sources will thus have to make it in the fuel market in the near term.

2. Remote Natural Gas

There are large quantities of associated and nonassociated natural gas which could be converted to methanol (see Chapter 3). To the extent that these resources do not have access to pipelines, have undeveloped markets in the host country, or that methanol production is more profitable than LNG conversion, there could be considerable methanol production capacity created in a reasonably short time. The lead time, for instance, for a barge-mounted methanol plant is about 3 years for a plant with a capacity of nearly 300 million gallons-per-year.

According to our calculations, the cost of producing methanol from this source in 1987 is shown in Table 4-33 for various feedstock costs ($1.00 and $1.50/$10^6$Btu) and discount rates (15%, 20%, and 25%).

Our reference case is that 20 pecent return is needed on such projects to compensate for the large risks involved. There are, however, possibilities for some leveraging by the World Bank in underdeveloped countries or by the governments of foreign manufacturers of barge-mounted plants (e.g., Japan). Under such an arrangement, an equity return of 25 percent could still be obtained on a 60/40 debt to equity capitalization and still be totally consistent with our overall 15 percent case in Table 4-33.**

* For example, there are existing plants in Canada and Mexico who may maintain access to below-market natural gas indefinitly, thus giving them a competitive edge.

** If debt is supplied at 16 percent interest, the overall cost of capital after taxes is (0.6)(.16)(1-0.51) + (0.4)(0.25) = 14.7%.

Table 4-33. METHANOL PRODUCTION COST FROM REMOTE NATURAL GAS - 1987

RETURN TO EQUITY	FEEDSTOCK COST ($/10^6 Btu)	METHANOL PLANT-GATE COST	
		$/gal	$/10^{6}Btu HHV
15%	$1.00	$ 0.42	$ 6.49
	1.50	0.47	7.26
20% Reference Case	$1.00	0.51	7.88
	1.50	0.55	8.50
25%	$1.00	0.66	10.20
	1.50	0.71	10.97

Under the most optimistic scenario examined, natural gas might be purchased and delivered to the plant gate for $1.00/10^{6}Btu with a 15 percent overall rate-of-return on 100 percent of the invested capital. With these assumptions, the plant gate cost of methanol would be approximately $0.42/gal or $6.49/10^6 Btu.* Even if such a scenario were to occur, it is not likely that large amounts of methanol could be financed in this manner--the World Bank and foreign government participation is likely to be limited to a few plants to demonstrate the concept and economic viability of projects in "a few selected countries."**

Two factors contribute to the likelihood of barge-mounted methanol plants being built before Western coal-to-methanol production facilities. First, they are less risky from a technological sense because commercially proven technology would be used throughout. A manufacturer would essentially deliver a turnkey plant which would limit the ultimate owner's exposure to construction risks. Second, such a plant would obviously be built with open sea access which would provide less expensive tanker transport for the methanol product. The estimate used in this study is four to five cents per gallon for transport from Cook Inlet on U.S. carriers, and twelve to fourteen cents per gallon from Indonesia on foreign carriers. A summary of these delivered costs are shown in Table 4-34 for both Cook Inlet and Indonesia.

The results shown in Table 4-34 illustrate why the existing industry centered in the Gulf Coast has some measure of protection against new entrants. Imported methanol from Indonesia is uncompetitive with chemical grade methanol after import duties (approximately 13 cents/gal) are added to the figures in Table 4-34. Even at 15 percent return, the delivered price

*Cost in dollars per million Btu is for higher heating value.

**World Bank, "Emerging Energy and Chemical Uses of Methanol: Opportunities for Developing Countries," April 1982, p. vii.

Table 4-34. METHANOL FROM ALASKA AND INDONESIA
(1987 operation in 1981 $)

	COOK INLET REQUIRED RETURN		INDONESIA REQUIRED RETURN	
	15%	20%	15%	20%
PRODUCTION COST*	$0.42	$0.51	$0.47	$0.55
TRANSPORT COST	0.05	0.05	0.14	0.14
DELIVERED TO LONG BEACH	$0.47	$0.56	$0.61	$0.69

* Feedstock cost is highly site-specific, but in this case, $1.00/ 10^6 Btu was assumed for Cook Inlet in that the collection system would not be started from a zero base, which would be true in some Indonesian sites. Thus, for Indonesia, the baseline assumption above was for $1.50/ 10^6Btu, whereas at $1.00/$10^6$Btu the delivered product costs would fall by approximately seven cents per gallon in each case.

would be $0.74/gal, which is higher than methanol from market gas, expected to be $0.67/gal based on market gas at $4.75/$10^6$Btu in 1981 dollars in 1987. Of course, at 20 percent return, the Indonesian methanol would be $0.82/gal.* Only at natural gas costs under $1.50 per million Btu, collected and brought to the methanol plant gate, would imported Indonesian remote gas-to-methanol begin to compete in chemical markets.

3. Near-Term Prospects for Coal-to-Methanol

There is virtually no incentive for large scale Western coal-to-methanol projects being built in the near term under purely private sector forces. Consideration of projects supported by the SFC will be deferred to a later section of this report.

The case for using Western coal to produce methanol is based on relatively low mine-mouth coal prices in the West, scaling plants upward to very large sizes at the mine-mouth (e.g., Badger plant), and pipeline transport of the methanol product to use centers. In the current market, none of these factors is sufficient to induce non-subsidized Western coal-to-methanol development. It must be kept in mind that the emphasis is on the near term (i.e. up to 1992), because the long-run concept of large plants located at Western mine-mouths with pipelines for moving methanol may be the ultimate

* Actually, prices would be higher to the Gulf Coast area since these transport costs are to Long Beach.

evolution of a large-scale fuel methanol market. However, before such growth can take place, the preconditions must be established and a natural progression of events must occur.

First, as was discussed earlier in this chapter, the economies-of-scale in methanol production are not as significant as in some types of chemical process plants. Measured cost capacity factors vary from 0.33 to 1.39, with the average about 0.6 overall.* In the case of methanol, much of the increase in scale is accomplished through additional process trains so that the individual units are not increased in size. In such cases, a better "rule of thumb" is to only scale subsystems at 0.9 scaling factors where additional process trains are added and at 0.6 where process units are expanded to the new capacity. If this procedure is followed for methanol plants, the weighted average scaling factor for the plant is about 0.85 since the major processes (gasification and methanol synthesis) are full scale at about 4000 to 5000 tons-per-day of methanol output. Some economies can be expected in coal handling and utilities, which accounts for some improvement in cost per unit of output as scale is increased. The implications of this scaling potential is that making very large plants (e.g. 25,000 tons-per-day and up) is not the total answer to making inexpensive methanol. The figures in Table 4-35 illustrate the effect of scale and the implied errors if the chosen scale factor is wrong.

As indicated in Table 4-35, the potential errors of using simple scaling factors are large. Studies which employ the traditional 0.6 factor for a factor of five scale-up when 0.85 is the "correct" value, introduce a 33 percent underestimate of capital cost to the project. Obviously, the potential errors are also large the other way. If 0.6 is correct, then the use of 0.85 in this study would introduce a 50 percent overestimate in a five-fold scale-up case. Two points are illustrated by this brief discussion. First, doing scaling by ratio factors is very imprecise and is only justified for

Table 4-35. POTENTIAL ERRORS IN SCALING COAL-TO-METHANOL PLANTS

	ACTUAL COST-CAPACITY FACTOR					
	0.6	0.7	0.8	0.85	0.9	1.0
			Percent Error			
Scale up 5 times at 0.6	0	-17	-28	-33	-39	-48
Scale up 5 times at 0.85	+50	+27	+8	0	-8	-21

*"A Review of Cost Estimates in New Technology: Implications for Energy Process Plants," Rand Corp., Edward Merrow, et al., R-2481-DOE, July 1979, p 77.

relatively modest scale changes. Second, although the resources available in this study would not permit* detailed estimates of large-scale plants, it is felt that in the absence of actual cost data showing otherwise that large economies of scale in coal-to-methanol production are very suspect under existing commercial technology. As a result, the incentive for industry to move to large coal-to-methanol plants is not great based on only modest expectations of scale economies.

A second consideration in early Western coal-to-methanol for West Coast markets is the probable location of the plant. Although the overall system would be less expensive with the plant at the mine-mouth** and pipelined methanol product, the volume necessary for construction of such a pipeline is extremely large; in fact, too large for a reasonable progression in coal-to-methanol plant sizes in the near term. The relationship between pipeline diameter and methanol output which would utilize its capacity is shown in Table 4-36 on an approximate basis. As is evident from this chart, a plant or cluster of plants would have to produce over 45,000 tons-per-day to utilize the capacity of a 20-inch diameter pipeline or approximately 70,000 tons-per-day to utilize a 24-inch diameter pipeline. Since it is very unlikely that a small pipeline (i.e., 10 to 12 inch) over such a long distance would be economically justified, early plants would have to utilize rail transport for

Table 4-36. DEDICATED PIPELINE CAPACITY FOR METHANOL TRANSPORT

PIPELINE DIAMETER (inches)	METHANOL OUTPUT (tons-per-day)
8	8,000
10	12,000
12	17,500
14	24,000
16	30,000
20	45,000
22	60,000
24	70,000

*In fact, until better data is available based on actual construction costs for a demonstration plant, doing detailed cost studies on large plants is not justified since it would not increase the accuracy of the estimate significantly.

**Assuming for the moment that construction costs would be the same at the mine-mouth compared to nearer the market, there is evidence that this assumption would not be true for early plants.

the methanol product if built at the mine-mouth. Thus, much of the advantage of mine-mouth conversion would be lost.

In addition to the transport factor, another consideration which weighs against mine-mouth plant locations is that mine-mouth construction would have a cost penalty in remote locations. Although each site would, of course, have unique characteristics, as a general guideline, remote Western sites would cost nearly 15 percent more than an Illinois location as a reference point. Thus, early coal-to-methanol plants which are likely to be sized at 4000 to 5000 tons-per-day at most and could not justify a dedicated pipeline would suffer an added cost penalty if located at the mine-mouth.

A final factor which could influence early coal-to-methanol plants is the fact that the Texaco gasifier is not yet fully commercial. Fully commercial systems, Lurgi and Koppers-Totzek, may not be as well suited to mine-mouth siting. These systems, because of the gasification processes, favor production of medium Btu gas or SNG along with methanol. Since this gas must be piplined or used at the production site, it is not well suited to mine-mouth sites. Thus, there are some forces which make the prospect of mine-mouth conversion and pipeline transport to California unlikely in the near- to mid-term.

Taking into account the considerations discussed above, there are only a few concepts for coal-to-methanol for West Coast markets which satisfy the various constraints. Three such cases were examined to determine if near-term coal-to-methanol would be competitive with other production sources and viable for California's end-use markets: (1) Lurgi technology producing methanol and MBG near the use site, (2) Winkler gasification and ICI methanol synthesis producing methanol at a Cook Inlet site, and (3) Texaco gasification at a Western mine-mouth site with rail transport of methanol product.

a. Case 1: California Site - 1992. Such a plant, if it were built, would employ commercial technology. Thus, we assume that the Dry Bottom Lurgi is the most reasonable gasification process in the near term. Second, since this process would produce by-product MGB or SNG, the plant would have to locate near a short-haul gas pipeline or a direct market. The logistics of rail transport of coal feedstock and the economies of scale in gasification and methanol synthesis implies a plant which produces approximately 2,500 tons-per-day of methanol and nearly 100 million-SCFD of MBG. The most likely plant site in the West is probably Texas because the MBG could be utilized nearby as a chemical feedstock. If the methanol is to be used in California, however, the least expensive end-to-end system would be to locate the plant near a railroad line (e.g., Barstow, California) then pipeline the gas a short distance to use in industrial or utility boilers. The costs of such a plant are described in Section B of this chapter and summarized in Table 4-37 with the remainder of the system costs.

b. Case 2: Alaskan Site - 1992. Another potential concept for near-term consideration is to utilize Alaskan coal near Cook Inlet for conversion to methanol. The appeal of this concept is that the subbituminous coal would be mined near the plant site and the product could be shipped by tanker

Table 4-37. NEAR-TERM (1987) PRODUCTION COST COMPARISON FOR COAL-TO-METHANOL CONCEPTS (1981 $)*

	CALIFORNIA PLANT SITE	COOK INLET PLANT SITE	WESTERN U.S. MINEMOUTH SITE
Methanol Output	2,425 tpd	5,000 tpd	5,000 tpd
MBG Output (10^6 SCFD)	98 SCFD	-	-
Feedstock Cost Delivered	$0.21	$0.16	$0.10
Conversion Cost	0.95	0.93	0.85
Product Delivery (plant to market)	0.02	0.05	0.10
TOTAL (methanol equivalent)	$1.18	$1.14	$1.05

*The assumptions for this case are from the reference case of 20 percent return on 100 percent equity capitalization delivered to a coastal power plant (e.g., Long Beach). Feedstock costs are $2.07/$10^6$Btu delivered in California and $1.25/$10^6$Btu for coal to the Cook Inlet plant, and $0.85/$10^6$Btu for mine-mouth coal in Utah.

to California ports. Some premium would have to be paid for construction at this location, but the transportation savings would be significant to West Coast markets. In addition, the opportunity cost for this coal resource, although low in sulfur, is not too high at the mine-mouth because of the high transport cost given its low Btu content per ton. Given the type of coal available for feedstock, the most likely gasification technology could be a Winkler system with ICI methanol synthesis. The cost analysis shown in Table 4-37 is for such a system.

A comparison of the estimated production costs in Table 4-37 shows that the options are fairly close in costs from all the sources. In fact, given the uncertainty in any of these estimates, it is not really possible to favor one over another. It is clear, however, that they are all too expensive to be viable versus gas-fed plants in this time period.

c. Case 3: Western Mine-Mouth - 1992. By 1992 the status of the Texaco gasification technology will be more mature, which would permit the construction of a mine-mouth plant with little or no gas by-product. The primary advantage of this concept is the potential efficiency gain of the Texaco system in methanol production. Transportation costs for coal are significantly reduced, but without a product pipeline the savings in coal transport is offset by the added methanol transport costs.

The obvious conclusion is that unsubsidized coal-to-methanol plants are not competitive sources of methanol in the short-run. Capital costs are too high to overcome the inexpensive feedstock costs of Western mine-mouth sites and the market is not sufficient to warrant methanol pipelines which are necessary for viable methanol from coal in the long term. It may still be sensible to build plants near the mine-mouth even before pipelines are built, because the total transport cost of coal and product is not significantly different among these plant options. Thus, as volume increased, the mine-mouth plants could gain further as pipelines are constructed.

4. Other Near-Term Options in California

Two other options do exist for producing methanol within California for transition applications in the near term: petroleum coke and biomass. Although neither of these feedstocks are plentiful enough in quantity to supply large-scale use of methanol for fuels in vehicles, they are indigenous to the state and potentially competitive for specialized uses. A summary of the delivered cost of methanol to use sites in California is shown in Table 4-38. The petroleum coke plant is assumed to be at a refinery site and therefore takes advantage of certain economies in offsites and materials handling costs, offsetting some of the economies of downsizing to 2000 tons-per-day of output. This scale is consistent with petroleum coke availability at the large refineries in the state. The projected methanol costs are competitive with the coal-to-methanol cases, but not with methanol from remote natural gas.

The biomass system is assumed to be scaled at 575 tons-per-day of methanol output on the basis that any larger system would require feedstock transport over too long a distance to be competitive. Thus, any economies in

Table 4-38. 1987 METHANOL PRODUCTION COSTS FROM CALIFORNIA FEEDSTOCKS (1981 $)*

	COKE	WOOD
Feedstock Cost	$0.26	$0.18
Conversion	0.77	0.91
Methanol Transport Cost	0.01	0.03
TOTAL	$1.04	$1.12

*Reference case assumptions used here were 20 percent return after tax on 100 percent of capital. Petroleum coke cost of $1.80/$10^6$Btu and Wood cost of $32/ton.

methanol conversion would be more than offset by added feedstock gathering costs.

The system using methanol from wood is slightly more expensive from our calculations than the petroleum coke case. Of course, it must be realized that the potential scale of this system is severely limited within the state and therefore it is not a potential large-scale methanol source. In addition, there are incentives in place which would further reduce these costs to system users. Credits exist which could reduce the apparent cost $0.40/gal for methanol from biomass feedstocks used in 10:1 gasoline blends, but even in neat uses the credits can be as high as $0.20/gal for firms with tax liability to offset. Thus, with the existing tax incentives, methanol from biomass feedstocks may be viable in selected small-scale applications.

5. Near-Term Summary

The dominant supply option for expansion of methanol capacity in the near-term is methanol from remote natural gas from Cook Inlet, Indonesia or other foreign sources. This competitive advantage is attributable to both technical and economic sources. There is an inverse relationship between the hydrogen content of potential feedstocks and the complexity of the plant needed to produce synthesis gas for the methanol synthesis process. Natural gas, therefore, has a significant advantage over coal-based systems owing to the high hydrogen content of natural gas. This relationship is illustrated in Table 4-39, where the capital cost per gallon of annual capacity is shown for a set of representative feedstocks.

Given the relationship of capital costs shown in Table 4-39, it is clear that unless the feedstocks for systems such as residual oil, coal and lignites are considerably less expensive than natural gas, there is no motivation* for building such plants. While these feedstocks will be less expensive versus market gas after deregulation, it will not be true for remote natural gas, which makes the latter source a dominant choice in the near to mid term. Another economic factor which may also be important in the near-term market is that the scale of efficient plant size is smaller for natural gas-based plants, thus making them more consistent with near-term markets. Finally, the technical risks of such investments are reduced because the technology has been used extensively at full-commercial scale. Thus, required returns may be lower for such plants because of lower technical risks, reduced scale of investment, and perhaps greater market flexibility, since these plants would utilize tanker transport which could service Japanese as well as U.S. markets.

6. Role of Synthetic Fuels Corporation

There is a real dilemma in assessing the Synthetic Fuel Corporation's role in methanol production. Unlike methanol, the marginal source of crude oil for the United States is imported crude from the Middle East. Thus,

*Excluding, of course, incentives provided by the SFC and alcohol fuel from biomass credits.

Table 4-39. APPROXIMATE CAPITAL COST* PER GALLON OF ANNUAL CAPACITY (1981$)

FEEDSTOCK	CAPITAL COST/ANNUAL GALLON
Natural Gas (Industrial Site)	$ 1.00
Natural Gas (Barge-Mounted)	1.50
Residual Oil	1.50
Coal	3.00
Lignite	3.40

*Capital Cost estimate is at a common site for total plant investment and is only for basic capital of construction excluding escalation interest costs, working capital and start-up costs.

the presumption is that any synthetic fuel plants which do come on line tend to displace foreign production. Actually, of course, it is not so clearcut. Synthetic fuel production will affect marginal supply sources both domestically and from imports. Price-competitive shale oil, for instance, could make some forms of tertiary recovery uneconomic. But even in this case, much of the impact is upon the same firms in either case and would affect growth rather than existing production capacity. The methanol industry is somewhat different. After 1985, when natural gas is deregulated and contracts for natural gas at below market rates expire, the existing U.S. production capacity will become the marginal producer for chemical methanol. Thus, the dilemma is whether the SFC should subsidize a project which might ultimately displace an otherwise viable U.S. plant. Most of these methanol projects which have been proposed to the SFC have projected fuel markets for their output, but the actual sales mix when they are put into operation could be quite different. Obviously, this problem does not apply to methanol converted to gasoline, but is a concern otherwise. As will be shown below, the support given by the SFC could make the difference of some projects competing in chemical markets where they would not if left to the private market.

The potential impact of SFC support of Western coal-to-methanol projects for use in California takes three forms: price guarantees to reduce the risk of falling market prices (possibly from foreign competition based on remote natural gas), loan guarantees which would permit some projects to leverage their financing significantly beyond what they could obtain without support, and price supports which would directly subsidize selling prices. The value of loan guarantees to the large energy companies is less significant than to consortia formed for project ventures since most of these corporations already have access to preferred interest rates and perform their financing on a

company-wide basis rather than for specific projects. In the case of project consortia, the effect of SFC loan guarantees is quite substantial. To illustrate this effect, one can simply take the two near-term coal-to-methanol projects described in Section B of this chapter and examine the impact of leveraged financing. As an example, it will be assumed that a project could be financed at 60 percent debt with a 16 percent interest rate and 40 percent equity which is expected to yield a 25 percent return after-taxes to equity holders. All other assumptions remain the same as in Section B. The results are summarized in Table 4-40 for a comparison of financing options, and an example of the impact of a particular price guarantee mechanism is also illustrated. In the latter case, the price guarantee takes the form of an initial price and guarantees real escalation of 2 percent annually over the general inflation rate compared to a base case where the product is assumed to escalate only at the rate of inflation (6%). Not examined in Table 4-40 is the price support impact since it is clear that with a sufficient price support any plant could be made viable.

As illustrated in Table 4-40, the combined effect of both incentives is sufficient to bring the minimum acceptable methanol price down approximately one-third from the unsubsidized case. Even this combined effect, however, is not sufficient to compete with remote natural gas from Alaska in West Coast markets which could be delivered to Long Beach for approximately $0.56/gal with a 20 percent after-tax return and $1.00/$10^6$Btu feedstock cost. Even remote gas to methanol from Indonesia could be delivered to West Coast fuel markets for $0.69/gal, which substantially undercuts any Western coal-to-methanol concept, and is also below the Alaskan coal case, which would be $0.81/gal when five cents for transport is added to the figures in Table 4-40, or the Western mine-mouth case, which would be $0.79/gal with rail transport.

7. Financing Impacts

The impact of required rate-of-return on coal-to-methanol production costs is illustrated in Figure 4-19, where the nominal after-tax rate-of-return is varied from 11 percent to 25 percent. Other assumptions in Figure 4-19 correspond to the reference case assumptions for the 5000 ton-per-day TCGP/ICI coal-to-methanol plant. With these highly capital intensive plants it is clear that the required rate-of-return is a crucial determinant of methanol product cost. In Figure 4-19, for instance, methanol cost rises from $0.56/gal to $0.65/gal, $0.73/gal, $1.00/gal and $1.36/gal at required rates of return of 11 percent, 13.5 percent, 15 percent, 20 percent and 25 percent, respectively. The reference case assumption is that these plants would require a hurdle rate-of-return within the transportation fuels industry* of 20 percent. Within that industry the actual means of financing is not that crucial because financing is done at the company level, not on a

* Meetings were held with the project evaluation staffs of several of the study sponsors to discuss the appropriate required returns on large projects like coal-to-methanol production. The criteria varied somewhat by company, but 20 percent in nominal terms or 15 percent in real terms emerged as the baseline value for the non-regulated fuel producers. On projects in developing countries where production risks or market risk are judged to be especially high, the required return might be raised to 25 or 30 percent.

Table 4-40. IMPACT OF LOAN GUARANTEES AND PRICE SUPPORTS ON MINIMUM ACCEPTABLE PLANT-GATE METHANOL PRICES (1981 $/gal)

PROJECT	1987 MINIMUM ACCEPTABLE PRODUCT PRICE			
	(1) PRIVATE VENTURE	(2) SFC LOAN GUARANTEE ONLY	(3) SFC PRICE GUARANTEE ONLY	(4) SFC LOAN AND PRICE GUARANTEES
ALASKAN COAL	1.25	0.92	1.12	0.76
CALIFORNIA SITE	1.45	1.11	1.27	0.93
WESTERN MINE-MOUTH	1.10	0.83	0.96	0.69

(1) The "Private Venture" case assumes that the owners require a 20 percent on total investment; the return must be earned assuming that methanol product escalates only at the general inflation rate (6%).

(2) The "SFC Loan Guarantee Only" case retains the assumption that owners will not count on real methanol product price escalation, but with loan guarantees they are able to attract 60 percent debt financing at 16 percent to complement the 40 percent equity share assumed to earn 25 percent after taxes.

(3) The "SFC Price Guarantee Only" case implies that the initial required price would be guaranteed to escalate at 8 percent annually (2% real) whereas project sponsors would normally require that the project yield the required return if the project escalates only at the inflation rate. It is further assumed that the project is financed with 100 percent equity financing at an after-tax return of 20 percent. No price subsidy is implied, however, just protection from prices not rising at 2 percent in real terms.

(4) The "SFC Loan and Price Guarantee" case combines both incentives: leveraged financing as in case (2) with the price guarantee escalating at 2 percent above inflation (case 3).

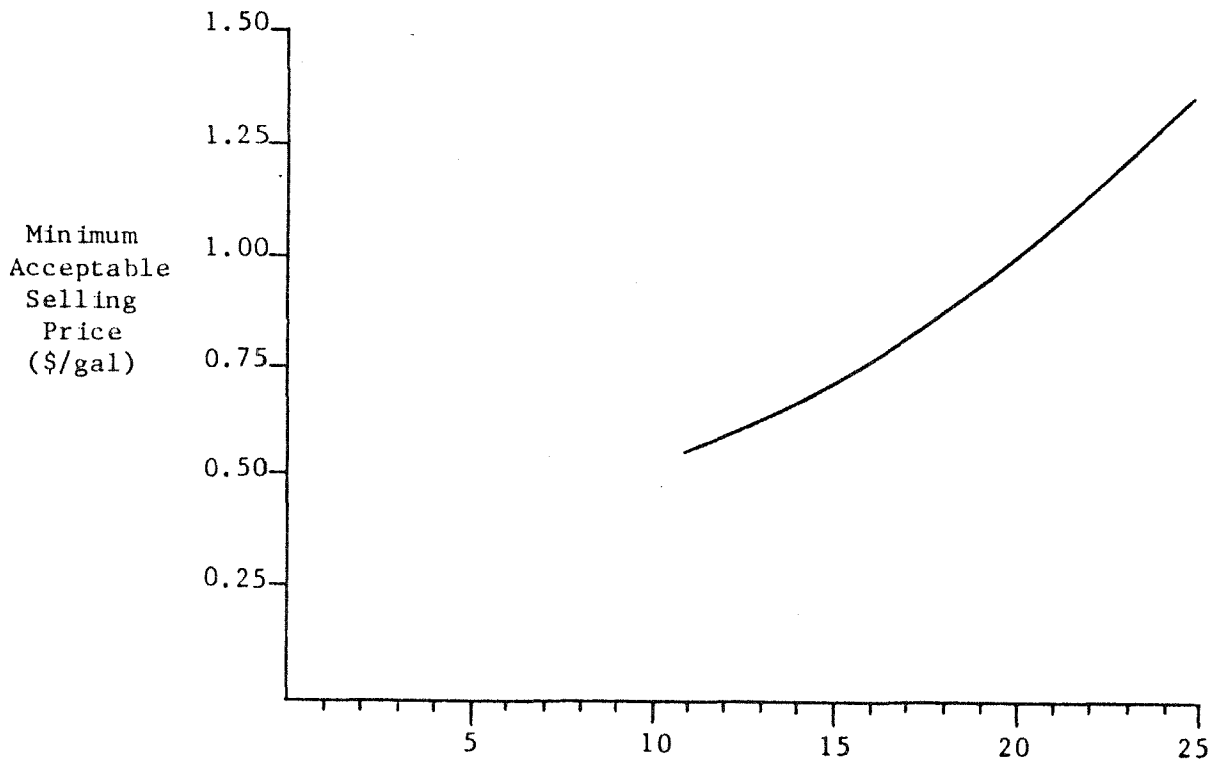


Figure 4-19. SENSITIVITY OF COAL-TO-METHANOL PRODUCTION COSTS TO REQUIRED RATES OF RETURN (1981 $)

project basis. Thus, the required returns used in this study correspond to hurdle rates of return which are used for decision making on whether projects should be pursued. Averaged realized rates-of-return may be lower than those used for decision making purposes, resulting from many factors in project implementation.

The sensitivities in Figure 4-19 are intended to show the impact on methanol minimum required prices of the financing costs associated with subsidized or guaranteed loans and regulated utility financing costs. An overall return on a project of 13.5 percent to 15 percent is comparable to the types of financing support which are being considered by the Synthetic Fuels Corporation.* Thus, the impact of loan guarantees to project sponsors who can

* For example, if the project equity support were required to be 30% of the capital investment and yield a 30% return, then with debt borrowed at 12% for the remaining 70% of the capital requirements, the nominal after-tax required rate-of-return (k) would be 13.2% with a 50% tax rate, [k = (.30) (.30) + (.12) (.70) (1-.5)]. This example is not implied to be a policy of the SFC, but rather an example of the potential impact of loan guarantees to some project sponsors.

take the full advantage of the tax benefits of the project as well as leverage the project is to lower the minimum acceptable price from $1.00/gal to $0.65/gal to $0.73/gal in this hypothetical example.

In the terms used in this study, the impact of utility financing on a project of this type would be to lower the minimum acceptable product price to approximately $0.56/gal.* Thus, the impact of financing is substantial, but it is also somewhat misleading to interpret this financing impact as a solution to lowering the cost of methanol production. The high returns required and low leveraging in the fuel production industry are a reflection of the higher production market risks in this industry. The kinds of returns allowed in the regulated utility industry simply would not compensate for these real risks. The financing incentives of the Synthetic Fuels Corporation are an attempt to subsidize projects by having the government assume some of this risk in order to stimulate a synthetic fuels industry. Thus, SFC support may be a way to get some experience with methanol production, handling, and marketing, but it likewise is not a solution to the high cost of methanol production unless risks and costs are actually reduced through experience.

8. Mid-Term (1992-1995) Coal-To-Methanol

In the mid-term period during the mid 1990s, there will be improvements in production technology which may lower methanol production costs. For example, the Texaco Coal Gasification Process (TCGP) process will have been demonstrated in the Coolwater project and will be ready for use in methanol production. The impact of this development is shown in Table 4-41, where the near-term coal-to-methanol options discussed in Section D.3 are compared with the TCGP process at plant scales of 5000 tpd and 10,000 tpd.

As demonstrated by the figures in Table 4-41, there are potential savings in conversion costs through increases in both efficiency and production scale. The TCGP process may be capable of reducing conversion costs slightly over 10 percent at comparable scales and another 10 percent in larger plants, reducing conversion costs to $0.74/gal. Of course, to really take advantage of mine-mouth conversion, the product must be shipped by pipeline to West Coast markets. For example, if total methanol output in the mid 1990s were at least 15,000 tons-per-day, the transport cost in a 14-inch pipeline would be approximately $0.07/gal, which would reduce delivered cost of methanol to California to $0.96/gal, as compared to the 10,000 tpd plant shown in Table 4-41.

The prospects for sufficient demand for methanol to induce large-scale coal-based plants during the early 1990s is very remote. Cost reductions of the type shown in Table 4-41 are not sufficient to open the market up to the large mine-mouth conversion/pipeline transport which would make methanol a widely used fuel. The only single factor which would significantly alter this

* As an example, if the allowed equity return were 16 percent for 50 percent of the project capital requirements and debt were obtained at 12 percent for 50 percent of the capital requirements, then the nominal after-tax rate-of-return k would be 11 percent with a 50 percent tax rate, [k = (.16) (.5) + (.12) (.5) (.5))].

Table 4-41. IMPACT OF MID-TERM TECHNOLOGY ON COAL-TO-METHANOL PRODUCTION COSTS* (1992 in 1981 $)

COST CATAGORY	PRODUCTION TECHNOLOGY			
	LURGI 5000 tpd	WINKLER 5000 tpd	TCGP 5000 tpd	TCGP 10,000 tpd
FEEDSTOCK COSTS**	$0.33	$0.16	$0.15	$0.15
CONVERSION COST	0.99	1.97	0.85	0.74
PRODUCT TRANSPORT COSTS***	0.02	0.05	0.10	0.10
MINIMUM ACCEPTABLE PRICE	$1.34	$1.18	$1.10	$0.99

* Reference case assumptions are used in financing: 20 percent return after-taxes on 100 percent equity capital.

** Feedstock costs represent $2.07/$10^6$Btu delivered to California for the Lurgi case, $1.25/$10^6$Btu at Cook Inlet for Winkler and $1.10/$10^6$Btu at the mine-mouth for TCGP systems.

*** Transport costs are for local rail transport for Lurgi, tanker transport for Winkler, and unit train from San Juan to LA for TCGP.

conclusion is if coal-to-methanol gasification and methanol synthesis becomes a much less risky investment, inflation subsides to a low stable rate and the cost of acquiring capital decreases. In such a case, highly capital-intensive systems like synfuel production improve significantly. In the example used above, for instance, if the combined effect of the above factors was to make a 15 percent nominal after-tax return adequate to attract capital, the plant-gate production costs for the 5000 tpd TCGP plant and 10,000 tpd TCGP in 1992 would fall to $0.73/gal and $0.65/gal, respectively. In terms of delivered minimum required prices to California markets, the respective values could be as low as $0.80/gal and $0.72/gal for these types of plants if transported through a high volume pipeline (e.g., 14-inch diameter). Thus, coal-to-methanol plants can ultimately be a competitive supply option but not until:

(1) Risks are reduced through successful demonstrations;

(2) Market and technical risks are sufficiently low that these highly capital-intensive plants are competiting for capital against options with risk adjusted opportunity costs nearer 15 percent after-taxes; and

(3) Demand has risen suffiently that less expensive supply options (remote natural gas for fuel markets and market gas in existing plants for chemical markets) become inelastic in supply.

The prospects for these criteria being met under the baseline energy price forecast before the mid to late 1990s are very unlikely for non-subsidized ventures, unless some firms are willing to accept returns of less than 15 percent after-taxes for these risky ventures. At this time there does not appear to be a willingness to do so.

9. Methanol Transition Supply Summary

From a transition period perspective, the most interesting characteristic of the near-term supply is what type of producer is a marginal production source. As was mentioned earlier, by 1985 most existing U.S. producers will be on market gas which will be approximately $4.50/10^6$Btu in 1981 dollars. It is highly likely that this type of capacity will be the marginal production source for the U.S. chemical market. Some producers will have a comparative advantage and do better in terms of their returns from sources like Canadian or Mexican remote natural gas. The marginal supply cost at the plant gate under this scenario should be in the range of $0.67/gal to $0.71/gal in 1981 dollars by 1987, which is composed of $0.54/gal in feedstock cost and the rest in operating cost and returns on working capital investments. At market prices below this level, these producers would be better off shutting down entirely if they cannot cover operating costs. Transport costs, the import duty of 18 percent, and the moderation in oil and natural gas prices are the keys to this scenario. Obviously, if oil and gas prices should accelerate rapidly in response to some exogenous change in the oil market, the domestic U.S. industry will be priced out of the market more rapidly by foreign producers. Figure 4-20 shows the relationship of the different supply options in the transition period.

A key implication of the deregulation of natural gas in this country is that very inexpensive methanol with a large excess supply for fuel markets is not likely. The reason is that the bulk of the U.S. producers operating on market gas have a threshold of obtaining $0.67/gal at the plant gate or they are better off closing down. Thus, there is a significant methanol capacity which leaves the market at lower prices. Other competitors from foreign sources must have plant-gate costs of $0.50/gal to compete, given transport costs and import duties which require remote natural gas at $1.00//$10^6$Btu or less, acceptance of a 15 percent return after taxes, and transport costs of $0.10/gal to the Gulf. There will not be too many foreign producers meeting these criteria. Thus, foreign producers who can land methanol on the West Coast for $0.50/gal to $0.55/gal in 1987 dollars will be better off selling into fuel markets than trying to penetrate the chemical market. Domestic Alaskan remote gas plants would have to be offered at least $0.63/gal to $0.65/gal to divert their output from competing in the chemical market, since they would not be subject to the duty. Thus, market forces will prevent large quantities of very inexpensive methanol (under $0.55/gal) from flooding the fuel market. Hopes that the increase in worldwide capacity will drive down methanol prices to very low levels are probably optimistic if one is expecting those low prices to stimulate new fuel uses.

The implications of Figure 4-20 are that for West Coast fuel uses, the remote natural gas option is the least expensive supply source. Lower feedstock costs ($1.00/$10^6$Btu) and transport costs ($0.05/gal) for the Cook

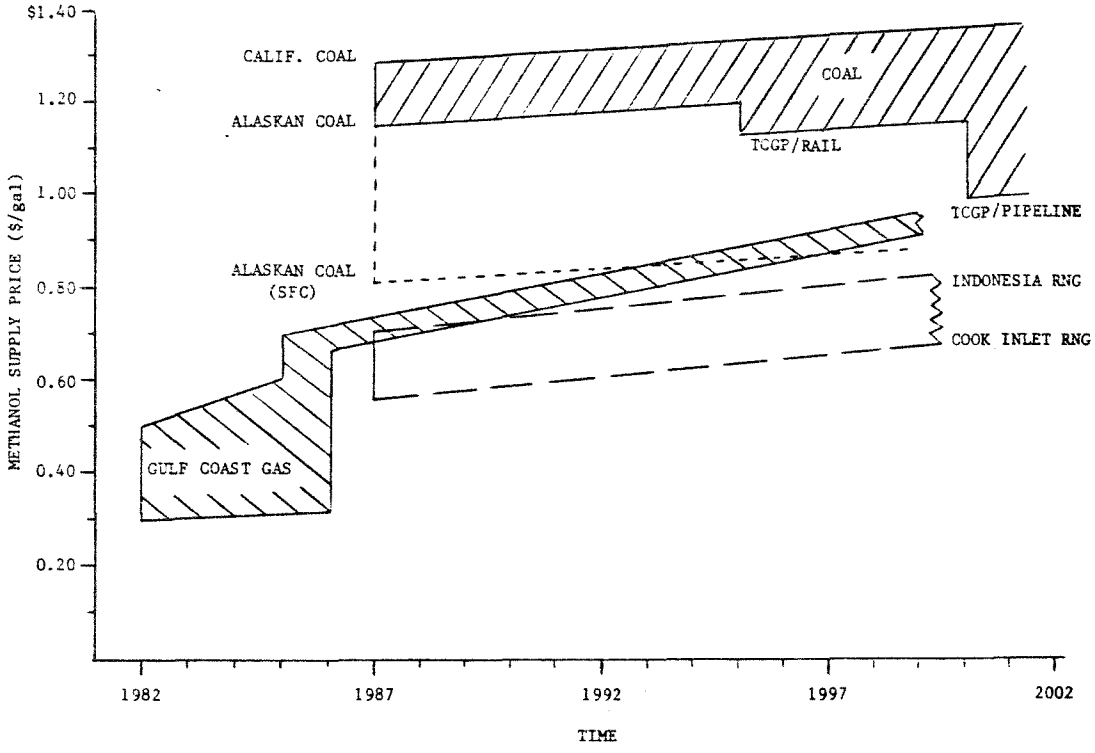


Figure 4-20. DELIVERED COSTS OF MARGINAL METHANOL PRODUCERS (1981 $)

Inlet case give it lower delivered product cost than Indonesian methanol (where $1.50/10^{6}Btu gas and $0.14/gal transport costs were assumed). The elasticity of supply from these sources is uncertain after two to three plants are constructed, but even that quantity (600 to 900 million gallons-per-year) is quite sufficient to supply California's near-term (up to 1992) demands under realistic market growth assumptions. Further studies on methanol should focus on this issue of characterizing the elasticity of methanol supply from remote natural gas. The transition will be affected by how rapidly marginal production costs rise as more capacity is added. For example, although the least expensive option is Cook Inlet at a minimum of $0.56/gal, the costs rise rapidly as feedstock escalates or longer transport distances are required (e.g., from Indonesia). The impact of these factors is illustrated in Table 4-42.

The precise dynamics of evaluating the remote natural gas supply industry are difficult to predict, but they will tend to exploit the most efficient resources first and then add more expensive options as production expands. There are a number of different characteristics of remote natural gas which would affect its value. The lowest opportunity cost of remote

Table 4-42. SENSITIVITY OF 1987 DELIVERED MARGINAL PRODUCTION PRODUCTION COST TO REMOTE NATURAL GAS COST (1981$/gal)

PLANT SITE	FEEDSTOCK COST ($/10^{6}Btu)				
	1.00	1.50	2.00	2.50	3.00
Cook Inlet	0.56	0.61	0.67	0.72	0.78
Indonesia	0.65	0.70	0.76	0.81	0.87

natural gas would be associated gas which is being flared. Associated gas which is being reinjected has a value in enhancing oil recovery from that of coal to that of oil, depending on the alternatives available. For non-associated gas the floor price which would be required for opening up a new field is considerably higher. Estimates from two industry sources* active in natural gas development are that $1.75 to $2.00/10^{6}Btu would be the minimum gas acquisition cost in this latter case. Obviously, the opportunity cost of remote gas could be higher than its acquisition cost in the field if there were higher value uses, such as conversion to LNG or ammonia. Thus, the acquisition cost of gas for methanol conversion is highly site-specific, depending on the opportunity cost of gas in each gas field. This discussion of gas cost is important because some projects can probably be established for gas acquisition costs from $1.00 to $1.50/10^{6}Btu based on low opportunity cost associated gas. Expansion beyond these quantities, however, will necessitate more expensive gas ($1.75 to $2.00/10^{6}Btu and up) for development of non-associated gas fields. Thus, we would anticipate that Cook Inlet is the initial site and that two plants could obtain natural gas at a delivered cost to the plant of about $1.00 to $1.50/10^{6}Btu. Beyond this level of production, however, the next lowest cost source of gas may be from Indonesia at a collected feedstock cost of $1.50/10^{6}Btu, which results in a delivered methanol cost to California of $0.70/10^{6}Btu. Thus, simply because there is a projected source of methanol at $0.56/gal delivered does not mean it is available in very large quantities at this price level. The marginal, delivered methanol price from remote natural gas could rise to the range of $0.70 to $0.75/gal before one billion gallons a year of production is achieved.

The potential for coal-based methanol to become viable is dependent upon the development of new technology and the actions of the SFC. In the near-term, the lowest cost coal option for delivered methanol to the West Coast is from Alaskan coal or western mine-mouth coal. As an unsubsidized venture, the cost of methanol would be too high to compete at approximately $1.10/gal to $1.35/gal delivered, but with SFC support, this cost could be reduced to about $0.80/gal in 1987. Although this cost is still not competitive with methanol from early remote natural gas plants at our assumed gas costs, coal-to-methanol

* Based on information provided through discussions with the technical staff at Chevron and Alberta Gas.

could find a market in the mid-term, if methanol demand expands in fuel uses. After a few remote gas plants are built in the most favorable locations taking advantage of existing infrastructure to lower collection costs, the cost of new sources will start to rise. For each increase in feedstock cost of $\$0.50/10^6$Btu the methanol product cost rises about $0.05/gal, thus the marginal cost of remote gas-to-methanol production could be pushed up to over $0.80/gal from Indonesia if feedstock is $\$2.50/10^6$Btu or more. Thus, a mid-term role for coal-to-methanol depends on two factors: SFC support and sufficient methanol demand to drive up the marginal cost from remote natural gas sources. As was suggested earlier, this pressure on remote gas prices is not likely to develop until at least three or more plants are in place, which could take ten to twelve years. The other factor which will tend to moderate remote gas price increases is the moderation in world oil prices will tend to reduce the value of LNG and hence the amount LNG producers can offer for remote gas resources.

In the longer term, coal-to-methanol production costs can be reduced as the Texaco Coal Gasification Process technology becomes commercial and is implemented in large (5000 tpd) methanol production processes. The higher efficiency of this system versus the Winkler technology could reduce costs about $0.10/gal at the plant gate. Significant economies, however, depend upon mine-mouth plant location with pipeline transport. Thus, in the year 2000 timeframe in Figure 4-19, the lower bound on the coal production cost region represents this case, where large TCGP/ICI plants (5000 to 10,000 tpd) are located near the mine-mouth and product is transported by pipeline to central distribution centers in California. This delivered cost could be in the range of $0.95 to $1.00/gal in 1981 dollars. An interesting coincidence is that the subsidized cost of methanol production from Alaskan coal in the near-term is reasonably consistent with the long-term lower bound on coal-to-methanol (adjusted for real escalation) delivered to California. Thus, if such a plant were supported by the SFC, it would not create an unrealistic market which could not be sustained by private industry in the long-run. The difficulty will be to find near-term markets, given methanol from lower cost, non-market natural gas producers and the threat of entry from barge-mounted remote gas producers. A final step in the long-run supply of methanol would be when the risks, both technical and market, are reduced sufficiently to permit the fuel supply industry to accept a rate-of-return closer to our 15 percent return-to-equity case. This return assumption with pipeline transport and mine-mouth coal costs would combine to make methanol potentially available to California users at about $0.73/gal in 1981 dollars. It must be remembered, however, that this is a long-run possibility which is dependent upon the successful resolution of some very real technical and market risks which by necessity will take the rest of this century to resolve.

F. POLICY OPTIONS FOR METHANOL PRODUCTION

As our discussion of the nearer-term production options has indicated, the least expensive major methanol sources reach California by sea. Longer-term options will probably utilize pipeline transport as part of the most efficient long-term system. Thus, the first policy premise for methanol transitions is to facilitate methanol transport into the state.

> Establish requirements for port facilities in California and address environmental and safety concerns. Priority locations are: (1) Long Beach, (2) Oakland, (3) power plant sites with terminal facilities (Ormond Beach and Mandalay).

The problems of moving and storing methanol in California ports do not appear serious, but there has to be a clear policy by all state agencies that firms will not face long delays which are caused by ignorance of this fuel and its properties rather than by any real problems. The same concern ultimately applies to pipelines entering the state from Western coal fields, but the lead times are much longer. The key point is that the critical path for methanol use in California does not depend on large-scale methanol production within the state in either the near-term or long-term. There will be some methanol produced from bioenergy sources in the state for localized consumption at non-grid-connected peaking turbines and possibly supply vehicle fleets in the transition period. The crucial supply options for large-scale use, however, are remote natural gas in Alaska's south slope, Canada, Mexico, Indonesia for the near-term and coal in Alaska or Western U.S. coal fields in the longer-term. Inexpensive transportation is crucial to utilization of these resources, which can only be accomplished through tankers and pipelines. Both of these transport options have similar costs for methanol delivery to California; about $0.05/gal for tanker from Cook Inlet and $0.04/gal to $0.07/gal for pipelined methanol from Western coal fields depending on pipeline size and coal field distance. Rail transport over comparable distances from Western coal would cost $0.10/gal or a difference of about $0.05/gal or $0.80/$10^6$Btu. A transportation savings of that magnitude is important in accelerating the cost-effective use of methanol in the state.

Another consideraton on the production side of the market is for the State to facilitate proposals made to the Synthetic Fuels Corporation for methanol production based on Western coal, Alaskan coal, or indigenous California resources (e.g., petroleum coke). This assistance could include: expedited siting procedures for petroleum coke or bioenergy plants, assistance in obtaining needed permits for port facilities, and market information on potential users within the state. This help should not be confined to production sources in California because methanol production within the state is not critical to the transition path. It is more important to support infrastructure development on facilities to import methanol and transport it efficiently between various use centers.

> Establish a liaison within the Synthetic Fuels Department of the CEC to assist applicants to the Synthetic Fuels Corporation by providing detailed California methanol market information and help in the permit application process (in the latter case for storage and transport primarily).

As one might expect, since production within the state is not viewed as critical to a methanol transition, there is relatively little the State of California can do on the production of methanol per se. The policies above, however, are important as part of the methanol delivery system. Notably absent from the discussion above is the recommendation that the California PUC encourage utilities within the state to co-produce methanol as part of a combined cycle plant operated on medium Btu gas. Since under most reasonable expectations for the future we do not anticipate synthetic gas to be competitive with natural gas or direct use of coal in electricity production, there is really no point in facilitating such an option.* Production of methanol as a fuel is a risky venture at this point in time, both technically and economically, for which utilities simply cannot be compensated under any foreseeable circumstances. Thus, we see little potential for utilities in the production of methanol in the near-term transitional phase. The relatively lower financing costs of utilities, compared to unregulated fuel production corporations, make capital-intensive projects like methanol and other synfuel plants look so much more viable under utility financing. It is important to realize, however, that these lower financing costs are based upon lower risk investments technically, and an absence of market competition. In the case of methanol production, utility production in the early phases of transitions merely exposes stockholders and customers to risk for which neither is compensated.

---

* One possible longer term exception would be that if the once-through methanol combined-cycle coal gasification concept is successfully commercialized, there could be benefits to co-producing, but this concept requires significant development and thus is not a factor in the nearer term.

G. CONCLUSIONS

In this chapter, an examination has been made of the production costs of alternative production technologies for methanol and other synfuels. Since extensive uncertainties exist in most of these processes with regard to their cost in commercial-scale operations, caution must be exercised in attaching too much significance to small cost differences. There are some instances, however, where much of the uncertainty is not independent and consequently reasonably firm conclusions can be drawn. Thus, the conclusions which follow appear to be reasonable interpretations and inferences of the data as it appears at the time of this work.

1. M-Gas is Non-Viable

Methanol production costs per 10^6 Btu from coal should be 17 to 19 percent less expensive than M-gas, resulting from a 10 percent increase in capital costs, and an 8 percent efficiency loss in further processing. This extra production cost is compounded in end-use efficiency loss of at least 15 percent in the fuel factor required for neat methanol vehicles versus gasoline, making the overall extra cost per mile traveled at least 30 percent and probably more. Thus, M-gas production is <u>not</u> an important near-term or long-term factor in the methanol transition, since M-gas cannot compete in the gasoline market.

2. Remote Natural Gas Dominates Coal

Methanol production in the near-term is dominated by remote natural gas as a feedstock. The processing requirements of coal-to-methanol imply approximately $3.00/annual gallon of capacity, compared to only $1.50/annual gallon of capacity for remote natural gas. Given this two-to-one advantage, one only considers coal if the feedstock cost offsets this major capital advantage. Our conclusion is that substantial remote gas deposits exist which could be obtained at $\$2.00/10^6$Btu or less, which makes coal-to-methanol non-viable as an unsubsidized venture through 1995.

3. Existing U.S. Chemical Methanol Industry Appears Viable

The moderation in the expectation of natural gas prices for 1985, given lower oil price forecasts, has made the existing production capacity viable in the mid-term. Using market gas at $\$4.50/10^6$Btu to $\$4.75/10^6$Btu in 1985 to 1987 (in 1981 $) existing producers will be able to compete in chemical markets with marginal production costs of $0.67/gal to $0.70/gal at the plant gate. Although remote gas from foreign sites will be less expensive at the plant gate, the combination of an 18 percent duty and transport costs of $0.10/gal from Pacific rim producers will keep most foreign competition out of the market. The U.S. industry will rely on its sunk capital to compete--new plants would not be viable based on market gas.

4. Methanol Is a More Valuable Fuel than LNG

If remote natural gas is the preferred feedstock for methanol in California, a concern is whether the resource would be used for LNG conversion instead of methanol. There is no doubt that strictly as an energy carrier in large gas deposits (i.e., over 300 million SCFD), LNG is less expensive to produce and ship under 5000 miles. At longer distances, the cost of transportation in cryogenic tankers becomes more of a factor. Some have suggested that even at distances 5000 to 10,000 miles the added shipping cost of LNG does not offset its significant production advantage. The key point that is often missed in these comparisons is that a million Btus of methanol and LNG are not of equal value in either stationary or transportation applications. In transportation on a Btu basis, methanol will be more valuable than gasoline because of the efficiency gain in neat methanol vehicles, while as an octane enhancer it has even a greater value. Thus, when value is considered, methanol will successfully compete for use of remote natural gas with LNG. In other words, methanol producers will be able to offer remote gas owners a small premium over potential LNG producers and still have a viable product in many circumstances.

5. Methanol Production within California is Not Essential

Given the significant cost advantage of remote natural gas over coal and petroleum coke, these resources are not important to the near-term transition. Other resources from bioenergy may compete in specialized applications (e.g., non-grid-connected peaking units) especially considering a potential $0.20/gal incentive in neat methanol uses and up to $0.40/gal in 10:1 gasoline blends, which come from tax advantages. Bioenergy, however, is not economic in large-scale uses, even for such things as dual-fueling a large boiler. Thus, both indigenous feedstocks and transporting feedstocks into California for processing are not crucial to a successful methanol transition.

6. Port Facilities and Pipelines are Key Factors

The key feedstocks for synthetic fuels for California are remote natural gas in the short-run and coal or shale oil in the long-run. In all these cases, processing will be done much more efficiently near the resource site. Thus, California needs to do all it can to facilitate entry points for products into the state. In the near-term, port facilities in Long Beach, San Francisco Bay and coastal power plants are important. In the long-run, pipelines from Western coal fields will be crucial links in efficient systems. It is clearly in California's interest to promote transportation competition between railroads and pipelines by supporting legislation which increases the state's transport options.

7. Methanol Prices will Not Fall Significantly in Mid-1980s

There are a number of methanol production facilities under construction throughout the world which come on-line in the early to mid 1980s. In spite of this added capacity, the market price of chemical methanol in the next 5 years will probably remain over $0.70/gal in 1981 dollars. The

deregulation of natural gas and the termination of "old" gas contracts by 1985 will leave the existing industry virtually all on market gas by 1985. The variable costs of production by such producers will be over $0.64/gal by 1985 if natural gas is $4.50/$10^6$Btu or more. Thus, any producer who cannot earn his variable costs will shut down. Thus, although there will be some infra-marginal producers earning larger returns (e.g., Canadian suppliers with below-market gas), the marginal U.S. producers will not sell below $0.64/gal, keeping sales in chemical markets at this level or higher when transport and some return is added. Some foreign producers will sell to West Coast fuel markets for a minimum of $0.53/gal. At prices lower than this, they can absorb the transport cost and import duty and compete for the chemical market at the Gulf. As a result, expectations of very inexpensive methanol (i.e., below $0.53/gal) resulting from excess capacity are unwarranted.

8. SFC Support of Coal-To-Methanol Plants

One of the implications of the Synthetic Fuel Corporation's potential support for coal-to-methanol plants may be to displace part of the existing U.S. chemical methanol production industry. Our estimates indicate that a coal-to-methanol plant, in Alaska's Cook Inlet for example, with SFC support could deliver methanol to California for about $0.81/gal by 1987 in 1981 dollars. The additional cost of transport from California to the chemical markets located primarily in the Gulf Coast would add enough by either train or tanker to bring the delivered cost to around $0.90/gal. An estimate of the variable costs alone of producing methanol from market gas in existing plants is $0.67/gal, ignoring capital amortization. This margin is probably sufficient for these producers to continue to make debt repayment and interest charges on non-fully amortized plants compared to the Alaskan coal case. Other coal-to-methanol projects, however, nearer to chemical markets and those with other incentives (relating to biomass feedstocks) may be able to undersell existing producers sufficiently to force them to sell at below full-cost recovery. Thus, the SFC should carefully examine applications for coal-to-methanol projects for this potential impact on U.S. industry. The intent of the Synthetic Fuels Program is to make the U.S. less dependent on foreign oil, not to subsidize some U.S. producers of chemicals into driving other U.S. producers out of business.

9. Methanol Must be Compared on a Systems Basis

The comparison of methanol to other synfuels production costs alone has limitations, given both uncertainties in estimates and the end-to-end system nature of the problem. Thus, although we have found that shale oil is potentially less expensive than methanol on a Btu basis, methanol appears less expensive on a per mile basis as a transportation fuel. All these systems must be pursued further to resolve key uncertainties in technology and conversion costs. More important, however, is the potential end-use efficiency gain of methanol in optimized passenger cars which can offset modest fuel cost penalties on a Btu basis. In addition, methanol has certain other advantages in its clean burning characteristics. Thus, on a production cost basis, choices between other synfuels and methanol are inconclusive and final conclusions are deferred until the chapter on policy, where all these factors can be weighed.

H. REFERENCES

1. Acurex, Alternate Fuel Strategies for Stationary and Mobile Engines: Evaluation of Clean Coal Fuels, Volume III, July 1981.

2. Badger Plants Inc., Conceptual Design of a Coal-to-Methanol-Gasoline Commercial Plant, FE-2416-43, Cambridge, Massachusetts, March 1979.

3. Bechtel Corp., Economic Feasibility of Synthetic Fuel Project, San Francisco, Calif., November 1981.

4. Chow, T. K. and D. W. Stanbridge. Screening Evaluations: Synthetic Liquid Fuel Manufacture, EPRI AF-523, Ralph M. Parsons Co., Pasadena, Calif., August 1977.

5. EPRI, Coal-to-Methanol: An Engineering Evaluation of Texaco Gasification and ICI Methanol Synthesis Route, Fluor Corp., EPRI AP-1962, Project 832-4, Palo Alto, Calif., August, 1981.

6. EPRI, Economic Evaluation of the Coproduction of Methanol and Electricity with Texaco Gasification - Combined-Cycle Systems, EPRI AP-2212, Project 239-2, Palo Alto, Calif., January 1982.

7. EPRI, Production of Methanol from Lignite, Wentworth Brothers and C.F. Braun, EPRI AF-1161, TPS 77-729, Palo Alto, Calif., September 1979.

8. Fydowski, R. A. and T. P. Cox, Methanol: Its Production, Use and Implementation, ASME.

9. Harlen, J. K., Starting with Synfuels: Benefits, Costs and Program Design Assessments, Ballinger Publishing Company, Cambridge, Mass., 1982.

10. Kermode, Dr. R. I., et al., The Potential for Methanol from Coal: Kentucky's Perspective on Costs and Markets, Kentucky Department of Energy, December 1979.

11. Kirshenbaum, N. W., A Preview of the Beluga Methanol Project, Placer Amex Inc., Alaska Coal Conference, University of Alaska, Fairbanks, Alaska, October 1980.

12. Litton Energy Systems, Barge-Mounted Methanol Conversion Plants, Houston, Texas, 1981.

13. Merrow, Edward W., et al., A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants, DOE, R-2481-DOE, Rand Corporation, July 1979.

14. Office of Technology Assessment, An Assessment of Oil Shale Technologies, OTA-M-118, June 1980.

15. Office of Technology Assessment, Energy From Biological Processes, Volume I, OTA-E-124, July 1980.

16. Office of Technology Assessment, Energy From Biological Processes: Technical and Environmental Analyses, Volume II, OTA-E-128, September 1980.

17. Office of Technology Assessment, Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Impacts, OTA-E-185, September 1982.

18. Rischard, J. F., Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries, World Bank, Washington, D. C., ISBN 0-8213-0018-0, April 1982.

19. Rogers, K. A., R. F. Hill, et al., Synthetic Fuels Summary, Engineering Societies Commission on Energy Inc., FE-2468-82, DOE Contract DE AC01-77-ET-10679, Washington, D. C., March 1981.

20. Rogers, K. A. and R. F. Hill, Coal Conversion Comparisons, Engineering Societies Commission on Energy Inc., FE-2468-51, DOE Contract EF77-C-01-2468, Washington, D. C., July 1979.

21. Rolnick, Paul D., et al., Alternate Strategies for Stationary and Mobile Engines: Evaluation of Clean Coal Fuels, Vol. III, PACE Corporation under contract to Accurex Corp., Mountain View, Calif., FR-81-99/EE, July 1981.

22. Rudolph, F. H. and P. K. Herbert, Conversion of Coal to High Value Products, Lurgi Symposium on Coal Gasification, Liquefaction and Utilization, University of Pittsburgh, August 1975.

23. Rudolph, F. H., The Art of Coal Gasification, The fourth International Symposium on Chemical Reaction Engineering, University of Heidelberg, April 1976.

24. Union Carbide Corp., System Development Corporation, Strategic Study of Synfuel Commercialization, TM-6158-014-00, Oak Ridge, Tennessee, January 1981.

25. U.S. Department of Energy, Cost Guide - Cost Factors: Capital and Operations and Maintenance Factors of Representative Energy Systems and Facilities, DOE/MA-0063, Volume 3, April 1982.

CHAPTER FIVE

TRANSPORT, STORAGE, AND DISTRIBUTION

A. INTRODUCTION

An effective and efficient transportation system is essential to assure the success of meeting the future methanol fuel needs of California. While methanol production capabilities must be greatly expanded to meet the future demands of consumers, the development of adequate transportation capabilities is equally important to ensure that the output may be moved to the user. Scenarios forecasting methanol production expectations and changes in the current fuel mix consumed in California also entail a need to expand and, in some cases, to modify the state's transportation system capabilities accordingly. Any analysis of energy delivery systems must include consideration of the transportation subsystems.

B. POSSIBLE SCENARIOS

The relationship of the methanol feedstock resource base to the processing plants or refineries and, in turn to the utilization sites, is a complex one, and it is obviously desirable to optimize the location of each of these components to the greatest extent possible. This will assist to maximize the efficiency of the existing transportation system and to minimize the need for new construction.

Certain geographical constraints exist within the framework in which the transportation system must function. The location of the feedstock resource base is fixed, and the existing demand regions within California have requirements which must be satisfied. For situations where the resource base and the demand region are located at a significant distance from each other, the transportation system plays a greater role, and it is critical that this role be coordinated with the fuel production function. For instance, the question arises whether the methanol production plant should be located close to the consumer rather than to the producer, therefore mandating the movement of large quantities of feedstock materials instead of smaller amounts of methanol. The options are further complicated by the variety of feedstock materials and their differing forms; i.e., liquid, solid, or gas, that are considered to be candidates for the production of methanol for California.

A number of resources exist that may be considered candidates for the production of methanol. Among these possibilities are natural gas, coal, urban waste, biomass, residual fuel, heavy oil, petroleum coke, tar sands, and oil shale. The sites where these potential methanol feedstocks are located are also a variable for consideration. The relatively low-grade and limited quantity feedstocks should only be considered if they are available within California. Both the western United States and Alaska have a sizable resource base of coal, and Alaska also has a substantial quantity of natural gas that shows promise. Furthermore, another possibility is the foreign

natural gas that is under-utilized at the present time. Table 5-1 presents the methanol feedstocks and locations which will be considered.

The various transport modes that are candidates for the conveyance of either the feedstock or the methanol itself are haulage via rail, pipeline, truck, water or some combination thereof. These transport modes and their compatibility with possible forms of freight are shown in Table 5-2. Further, Table 5-3 illustrates the compatibility of these transport modes with the various feedstocks themselves.

The importance of considering the relationship of the location of the production plant to the location of the feedstock base should not be overlooked, since the most compatible type of transport may have distance constraints that impose limitations upon the system. Also, the locational relationship of the methanol production plant to the utilization or demand region is likewise significant. For instance, one of the factors affecting the economies of power plant siting is the cost of delivering the power to the load center as compared to the cost of delivering fuel to the power plant. If a number of suitable sites are available between the fuel source location and the load center, the utility may choose remote power plant siting with power transmission replacing fuel transportation.

Another factor is the tradeoff to be considered between the two most viable methanol utilization candidates. The use of methanol as an automotive fuel will require a vast, dispersed distribution infrastructure. The utility

Table 5-1. LOCATION OF POTENTIAL METHANOL FEEDSTOCKS

POTENTIAL FEEDSTOCK	LOCATION			
	CALIFORNIA	WESTERN U.S.	ALASKA	FOREIGN
Natural Gas			X	X
Coal		X	X	X
Urban Waste	X			
Biomass	X			
Residual Fuel	X			
Heavy Oil	X			
Petroleum Coke	X			
Tar Sands	X	X		
Oil Shale		X		
X denotes potential				

Table 5-2. TRANSPORT MODE CAPABILITIES

TRANSPORT MODE	COMMODITY TRANSPORTED		
	SOLID	LIQUID	GAS
Rail	X	X	
Pipeline	X	X	X
Truck	X	X	
Ship	X	X	X
X denotes potential			

Table 5-3. TRANSPORT MODES FOR POTENTIAL METHANOL FEEDSTOCKS

COMMODITY CONVEYED	TRANSPORTATION MODE			
	RAIL	PIPELINE	TRUCK	SHIP
Methanol	X	X	X	X
Natural Gas		X		X
Coal	X	X	X	X
Urban Waste	X		X	
Biomass	X		X	
Residual Fuel	X	X	X	X
Heavy Oil	X	X	X	X
Petroleum Coke	X		X	
Tar Sands	X	X		
Oil Shale	X	X		
X denotes potential				

power plant demand area would, however, provide a relatively concentrated demand region. Each of these utilization options has favorable aspects which must be analyzed and the transportation considerations are but a single factor.

It can be seen that a large variety of resource base-methanol production-utilization scenarios are possible. In order to assist in visualizing the numerous options, Figure 5-1 provides a simple schematic which outlines the choices.

C. TRANSPORTATION TECHNOLOGY

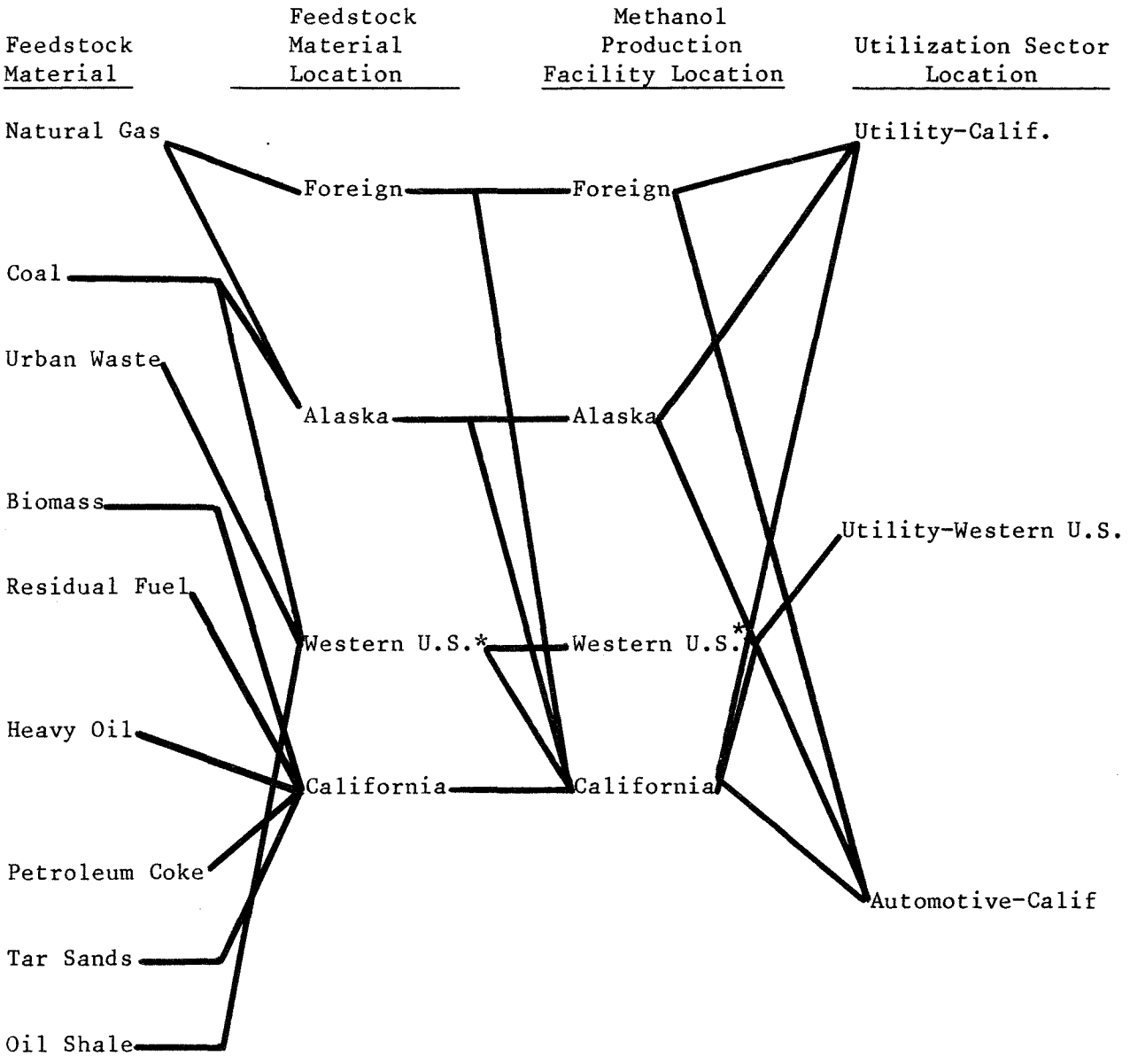
An awareness of their characteristics is essential to understanding the capabilities of the major transportation modes to satisfy the needs of conveying methanol and its potential feedstocks. The material that follows attempts to provide a preliminary framework for that understanding.

1. Rail

In the past, railroads have handled the majority of the coal transport requirements for the country, and it is anticipated by most that the railroads will continue to be the principal mover of coal in the foreseeable future as well. This is considered significant, since coal has been identified as one of the most promising feedstocks for methanol production. This coal traffic is typically handled by unit trains which are designed to take advantage of scale economies and are dedicated for service between two points with a sufficient volume to achieve cost savings. The cars are designed for automated loading and unloading, and the train is operated to avoid switching and delays in freight yards. A typical unit train consists of six 3000 horsepower locomotives and 100 hopper cars with a capacity of 100 tons each. A methanol production facility with the capability of producing 5000 tons/day or approximately 1.5 million gallons/day of methanol would require about one unit train shipment of coal per day from the Western coal fields in order to satisfy its feedstock requirements. A similar approach consisting of a dedicated quantity of rail tank cars can also be used for achieving the previously mentioned advantages when conveying a liquid commodity such as methanol.

Any rail transportation into California must confront the constraint of available traffic capacity of the existing corridors which traverse the natural transportation barriers surrounding California. All rail traffic in or out of California must pass through one of the seven key rail lines. The total capacity of these seven links is 44,000 trains/year, and their current utilization is about 21,000 trains/year (Ref. 1 & 2). Consequently, a significant increase of rail traffic could be accommodated in principle within the present system. In practice, public acceptance of such increases may not be so easy to obtain due to a variety of environmental and nuisance problems. California's rail system has a cumulative mileage of about 7,300 miles and is shown in Figure 5-2.

The potential upgrading and increased maintenance of existing track because of the heavier rail loadings from unit train traffic is not considered



* - Western U.S. designates non-California

Figure 5-1. POSSIBLE METHANOL FEEDSTOCK - PRODUCTION - UTILIZATION SCENARIOS

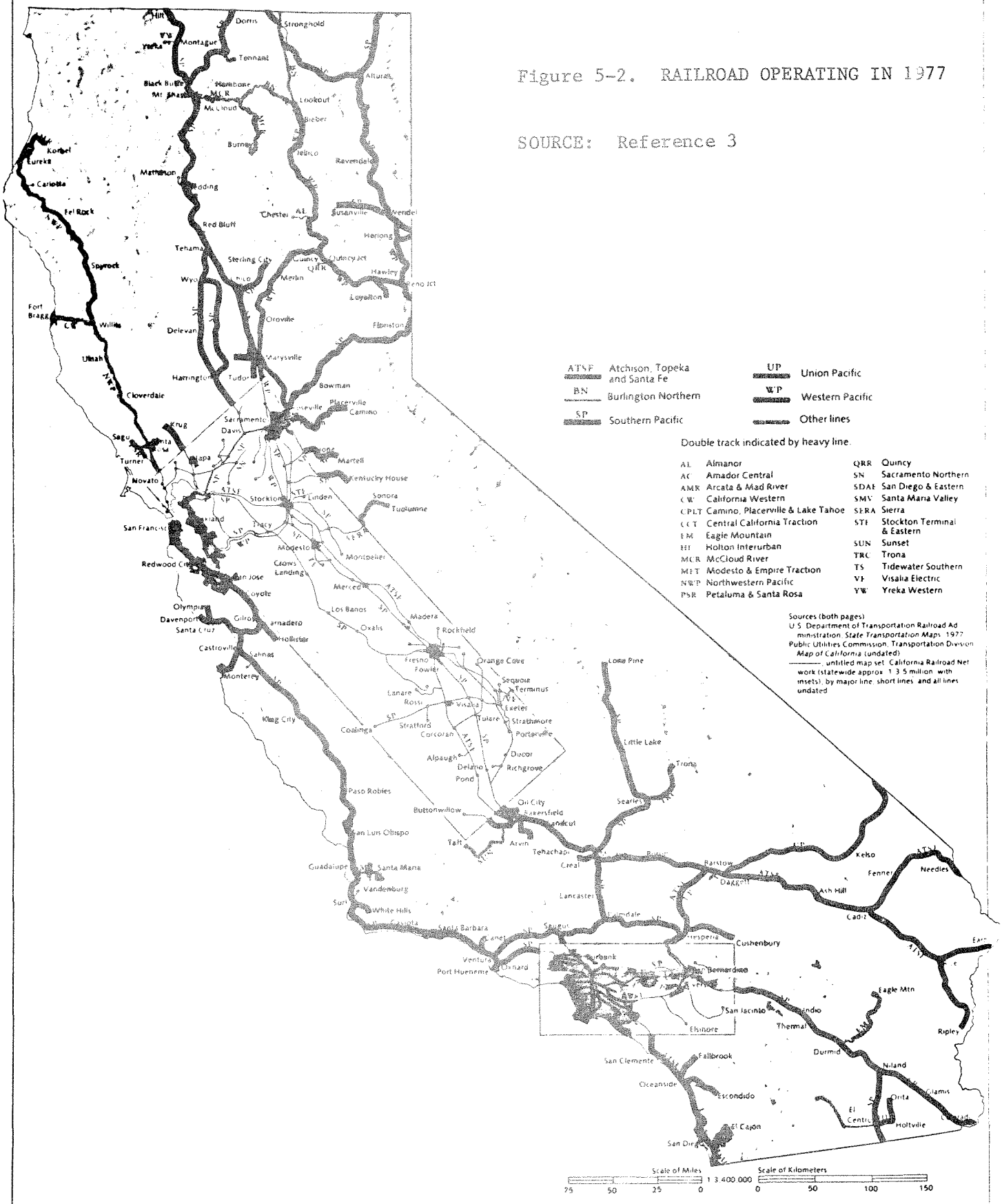


Figure 5-2. RAILROAD OPERATING IN 1977

SOURCE: Reference 3

a problem by the railroads. Further, the industry's production capacity for hopper cars and locomotives is sufficient for the additional equipment requirements that would be necessary to handle the increased coal traffic (Ref. No. 1). Consequently, within the timeframe of the next 20 years, the rail mode of transportation in California must certainly be considered as a prime contender for the conveyance of either methanol or its feedstocks, particularly coal.

2. Pipeline

The pipeline mode of conveyance is quite versatile and can quite easily accommodate either liquid or gaseous commodities as well as conveying solids via a slurry. Thus, it has potential for transporting either the feedstock to the production plant or the methanol itself. A substantial pipeline infrastructure exists within California, and this is illustrated in Figure 5-3.

Major developments in pipeline transmission in the U.S. in recent years have been significant in both the number and nature of such innovations. First, a trend toward greater pipe size has occurred. A number of other developments have also taken place, such as the introduction of the use of high tensile strength steel. This development has reduced the wall thickness of the pipe and lowered the number of tons of steel required per mile for pipe, thus reducing the investment required.

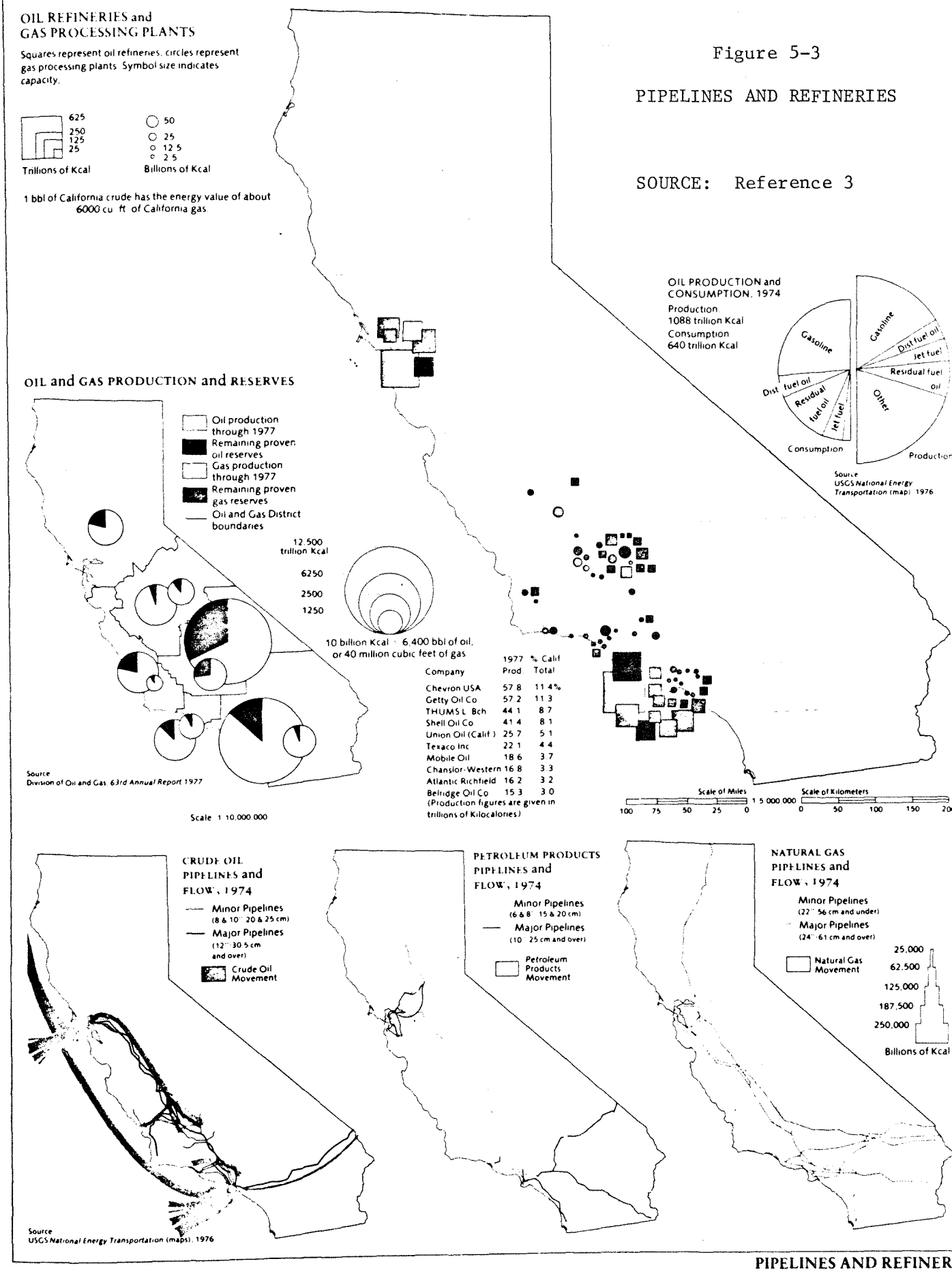
The automation of pump stations has decreased the personnel needed for the pipeline system operation. It is now common for pump stations to have no operating personnel at the station with control coming from a center hundreds of miles away. Many instruments have been developed for use in conjunction with pipeline transmission and distribution systems, permitting highly automatic control system design and operation. Improvements have also been made in corrosion prevention on pipelines, including the use of external and internal coatings and the use of cathodic protection to prevent corrosion.

A significant development is the closed-system oil pipeline. With older lines, it was necessary to remove the oil or product from the line temporarily at intermediate pumping stations and to store it in tanks. Now intermediate storage can be eliminated, and the product removed only at the destination. Furthermore, improved methods of communication and control have made it possible to deliver a variety of products, slugwise, through the same pipes with little co-mingling or contamination of products. While some pump seals and valve materials may have to be changed, the problem of material compatibility of the existing pipeline itself with methanol appears to be minimal according to some investigators. This concept of utilizing the existing pipeline infrastructure may be quite attractive, however, it should be noted that corrosion and material compatibility problems have not been uniformly observed by all investigators. Materials and techniques for pipeline insulation have also been improved. Polyurethane foam is one of the best insulators for pipelines. It is reported that the Trans-Alaska Pipeline is using this material to maintain a fairly uniform temperature and prevent the oil from becoming solidified by excessive cooling. Technology in welding has been greatly improved, so that stronger welds may be obtained in less time than it used to take.

Figure 5-3

PIPELINES AND REFINERIES

SOURCE: Reference 3



PIPELINES AND REFINERIES

a. Liquid Pipelines. Obviously, the greatest utilization of pipelines for the conveyance of liquid products is the system for transporting oil and its refined products. In the United States in 1977, about 78,000 miles of pipeline were used to carry crude oil, and approximately 81,000 miles carried finished products (Ref. 5). As previously stated, the use of this existing infrastructure could be beneficial in assisting in the transport and distribution of methanol and providing for a smoother transition than would otherwise be possible. However, as illustrated in Figure 5-3, there is a lack of existing pipelines from the bordering western states into California as well as within California.

As is pointed out in the methanol production section of this report, it is not realistic, particularly in the immediate future, to expect the methanol production facilities to support the construction or use of a dedicated pipeline. Since pipelines which cross state borders are classified as common carriers, they must carry products of any type and from any company. The use of batching methanol in petroleum products pipelines may be an attractive near-term transport option if material compatibility is not a serious problem. This calls for the use of inflatible "batching spheres" or pigs between different shipments. Radioactive isotopes are often used to signal the end of each successive shipment. The "common carrier" designation allows the pipelines to exercise the federal power of eminent domain. Without this classification, right-of-way access for pipelines across easements owned by railroads may be very difficult to obtain.

Recent oil pipeline innovations include "Teflon" lining to reduce friction, polypropylene coatings to prevent corrosion, and a growing use of all-plastic pipe for small gathering lines.

Automation helps reduce pipeline transport costs. Pumping stations run unattended, valves are operated by remote control; computers handle dispatching and accounting, and monitor conditions throughout the system.

b. Gas Pipelines. Even though it is unlikely that large domestic supplies of natural gas would be used as a feedstock for the manufacture of methanol, it is possible that remote, relatively small pockets of domestic natural gas could be utilized. Furthermore, a possibility exists for the coastal gasification of liquefied natural gas (LNG) that has been conveyed by tanker from an Alaskan or foreign field. Therefore, a brief synopsis of natural gas pipeline transport is in order.

Typically, gas is withdrawn from the ground through a pipe, called a casing, that extends to the bottom of the well. Then it is gathered by a piping system from various wells in a given area and delivered to some central point. From there it is transported over long distances by transmission companies and either placed in underground storage near the consuming areas or delivered to "city gates," where it is supplied to distribution companies for further transport. Generally speaking, compressors are used to force the gas through pipelines, and booster stations are required every 40 to 100 miles. The gas is transported under a pressure of about 800 to 1000 psi, i.e., 50 to

70 times atmospheric pressure, in these long-distance systems. In the U.S., about 1 million miles of buried pipeline, some of 42-inch diameter, linked our gas fields to compressor stations and, in turn, to consumers in 1978 (Ref. 5).

Since the overall demand for gas is usually low in summer and high in winter due to large domestic use, many transmission companies have developed underground storage close to consuming areas. The gas is injected into such storage pools in the summer months and withdrawn in winter, in order to provide a basis for year-round pipeline operation at high levels.

By the application of 1000 psi, approximately 68 cubic feet of natural gas is compressed into one cubic foot. Whenever the gas has insufficient pressure for its required movement, a compressor station must be used. The following types of compressor stations are in general use:

(1) Field or gathering stations gather gas from wells in which pressure is not sufficient to produce a desired rate of flow into a transmission or distribution system. Such stations may handle suction pressures from below atmospheric pressure to 750 psi, and volumes from a few thousand to many million cubic feet per day.

(2) Relay or mainline stations boost pressures in transmission lines and are generally of large volume and operate with low compression ratios. Their pressure range is usually between 200 and 1000 psi.

(3) Storage field stations compress trunk line gas for injection into storage wells and may produce discharge pressures of up to 4000 psi typically at high compression ratios.

(4) Distribution plant stations ordinarily pump a fluid from a primary supply to medium- or high-pressure distribution lines.

c. Slurry Pipeline. A third type of pipeline is one that is designed to convey a solid commodity with a liquid carrier. Such a pipeline may be considered for transporting either the coal to be used for the methanol feedstock, or possibly a combination of coal and methanol. Like unit trains, slurry pipelines can be well suited to satisfy the transportation requirements of Western coal. It has been found that in many cases slurry pipelines can transport coal for about the same cost as the railroads. Furthermore, the slurry pipeline can realize a significant cost advantage over the rail system unit trains for the movement of quantities of coal greater than 6 million tons/year over distances greater than 1000 miles (Ref. 6).

A coal slurry mode of transportation, while not exactly a common method, is certainly far from being a new idea. There is one coal slurry pipeline operating in the U.S. and several others in various stages of planning and design. There are currently five coal slurry pipelines which are being planned for the transporting of Western coal. These pipelines would have a total capacity of 88 million tons/year and would cover a total distance of 4700 miles. The typical coal slurry pipeline would convey a size of coal which would range from a .0937 to a .0017 inch diameter particle size. The coal would be combined with the transport liquid to form a slurry with a

nominal 50% solids content by weight density. Some laboratory investigators contend a 70/30 coal/water mixture by weight may be possible but this has not been adequately demonstrated with existing technology.

Transport Liquid - Water. All the previously mentioned coal slurry pipelines have one common denominator. This is the use of water as the fluid provided as a transport media for the solid particles of coal (approximately 50% by weight) in the slurry. Consequently, the issue which appears to create the most concern at this time is the use of water by the proposed coal/water slurry pipelines. The Western coal fields are located in semi-arid regions, and water is a highly valued commodity for agricultural, municipal, and industrial uses. Ironically, even though the mining of the coal itself requires very little water, most of the associated industrial uses of the coal such as power plants, coal/water slurry pipelines, liquefaction plants, etc., do require a significant quantity of water. Since the traditional coal/water slurries operate on a 50 percent by weight mixture of coal and water, they would remove a ton of water from the area for every ton of coal which was conveyed in the slurry pipelines.

One proposed approach by some of the coal/water slurry proponents is to obtain water from the large, natural underground water reservoirs known as aquifers, which may be located in the vicinity of the Western coal fields. Opponents of this concept have expressed concern that even though an aquifer may contain a sufficient quantity of water, the continual removal of water from it could result in unpredictable geological activity or affect the surrounding watertable. While some contend that the aquifers are rapidly being depleted, most observers agree that water supply should not be an obstacle.

However, aside from the water issue and the political problems related to the power of eminent domain needed to assemble the necessary pipeline right-of-way, it is a viable option whose technology has been proven.

Transport Liquid - Methanol. There has recently been a considerable amount of interest shown toward the concept of utilizing a coal-combustible liquid mixture as a boiler fuel. The U.S. Department of Energy is currently supporting extensive activity in this area. This idea is not a new concept, but rather one that has received renewed interest.

By utilizing a coal-derived liquid such as methanol as the transport media for a coal/combustible liquid slurry, there are several advantages to be obtained over the more conventional coal/water slurry. Some of the more pronounced incentives are listed as follows:

(1) The coal/methanol slurry would provide a fuel of a higher calorific value than could be obtained from a coal/water slurry.

(2) For a given required firing rate at the electrical generating station, a lesser quantity of coal/methanol slurry would be required than of the coal/water slurry. This would result in a

smaller diameter pipeline, as well as smaller capacity pumps and drivers.

(3) It would avoid the controversy of removing the water resources from the pipeline originating site, since the methanol would be used as the transport media.

(4) A coal/methanol slurry could be more adaptable (require fewer modifications) to existing, in service, oil-burning boilers than would be coal alone. This is based upon the testing currently being conducted with coal-oil mixtures by the New England Power Service Company and Florida Power and Light. Therefore, acceptance and conversion by the utility industry would be greatly enhanced.

(5) The use of a coal/methanol slurry would result in a higher boiler efficiency but not necessarily a lower cost than a coal/water slurry. This is due to the elimination of the high-moisture content of coal after being transported via a water slurry.

However, it is possible that the economic value of the methanol and the federally mandated fuel-use factors might prohibit its use in such a manner. It could very well be more prudent to separate the coal and methanol at the terminus of the slurry pipeline. Such a synergistic relationship should be investigated further in evaluating the various market potentials as well as further defining the safety, environmental, and technical aspects of such a concept.

3. Truck

Probably the most versatile and the most widely dispersed network (covering about 171,000 miles in California, Ref. 7) of the various transportation modes is conveyance by truck. However, the use of trucks via the highway system is commonly restricted to short hauls and as a method of transfer. They are not economically competitive for large volumes and long distances. For instance, as opposed to the average haul of 300 miles by railroad, and 480 miles by barge, the average highway shipment of coal by truck is only 50 to 75 miles (Ref. 8).

The trucks used for the highway transport of bulk solid materials such as coal have a capacity range of 15 to 25 tons each. The typical tank truck used to convey liquid products has a capacity of about 9,200 gallons. The standard diesel tractor is used to pull one and sometimes two trailers, depending on weight limitations. A significant quantity of coal movement also takes place on private roads using vehicles too large for public highways. Some of these vehicles can carry up to 150 tons of coal.

As previously stated, truck transport would usually not be considered as a primary means of conveyance for large quantities of solid or liquid feedstocks such as coal or oil between concentrated supply and utilization areas. Rather, it would more likely be employed to supplement another mode of transport such as rail or pipeline. However, the use of trucks may be particularly suited for the type of short hauls expected to be necessary to satisfy the

various regional characteristics anticipated for the delivery of feedstocks such as biomass or urban waste. Such methanol production plants would be expected to be significantly smaller and rely upon a rather widely scattered feedstock supply area as compared to a coal-to-methanol plant.

Truck transport is also necessary for satisfying distribution requirements to numerous service stations scattered throughout California, if methanol is to be used in either the neat or blended form as an automotive fuel. A typical service station pumps about 75,000 gallons of gasoline per month. Therefore, a monthly tank truck shipment of 9,200 gallons (average capacity per truck) could supply sufficient methanol for a 12% blend with gasoline, however, on-site storage would be needed for the methanol, which would add to the cost.

If methanol is intended as a fuel for electrical generating station gas turbines or boilers, then delivery by tank truck is one of the possible means of transportation. The distribution of such potential electrical generating units within California is illustrated in Figure 5-4.

4. Ship

The waterway system currently provides the most economic means for freight transport in the United States. Unfortunately, this system has some significant limitations regarding its ability to serve California as a viable option for the transport of either fuel methanol or its feedstocks. The transportation of both crude oil and petroleum products via water for California in 1974 is shown in Figures 5-5 and 5-6, respectively.

a. Barge. The equipment required for the shipment of freight, either solid or liquid, by barge includes the tugs, or self-propelled vessels that push the "tow", which is composed of several barges of either the dry cargo or tank type. A typical tow of tank barges consists of four barges and the towboat. A tow composed of dry cargo barges has, however, been known to consist of as many as 36 barges, with a 1,500 ton capacity.

Modern steel barges are of numerous designs to handle differing commodities. Their bows and sterns are usually formed to fit into a neat tow that presents an unbroken, low-friction surface to the water. The average speed of a tow is five miles per hour upbound; ten miles per hour downbound. A tow typically requires twelve hours to load and twelve hours to unload. A double-skinned tank barge 35 feet x 195 feet x 12 feet, known as a "jumbo," costs approximately $350,000, a "jumbo" open barge about $160,000 and a 5000 horsepower towboat costs approximately 2.6 million 1975$ (or approximately 4.0 million 1981$, Ref. 9). In 1978, there were approximately 4,380 towboats and tugs, 24,037 dry cargo barges, and 3,946 tank barges in the U.S. (Ref. 5).

However, it appears that this means of conveyance will be of little, if any, importance for the purpose of conveying methanol or its feedstocks in California. The only possible use would be in the San Francisco to Sacramento Delta area, where relatively small production plants utilizing biomass feed-

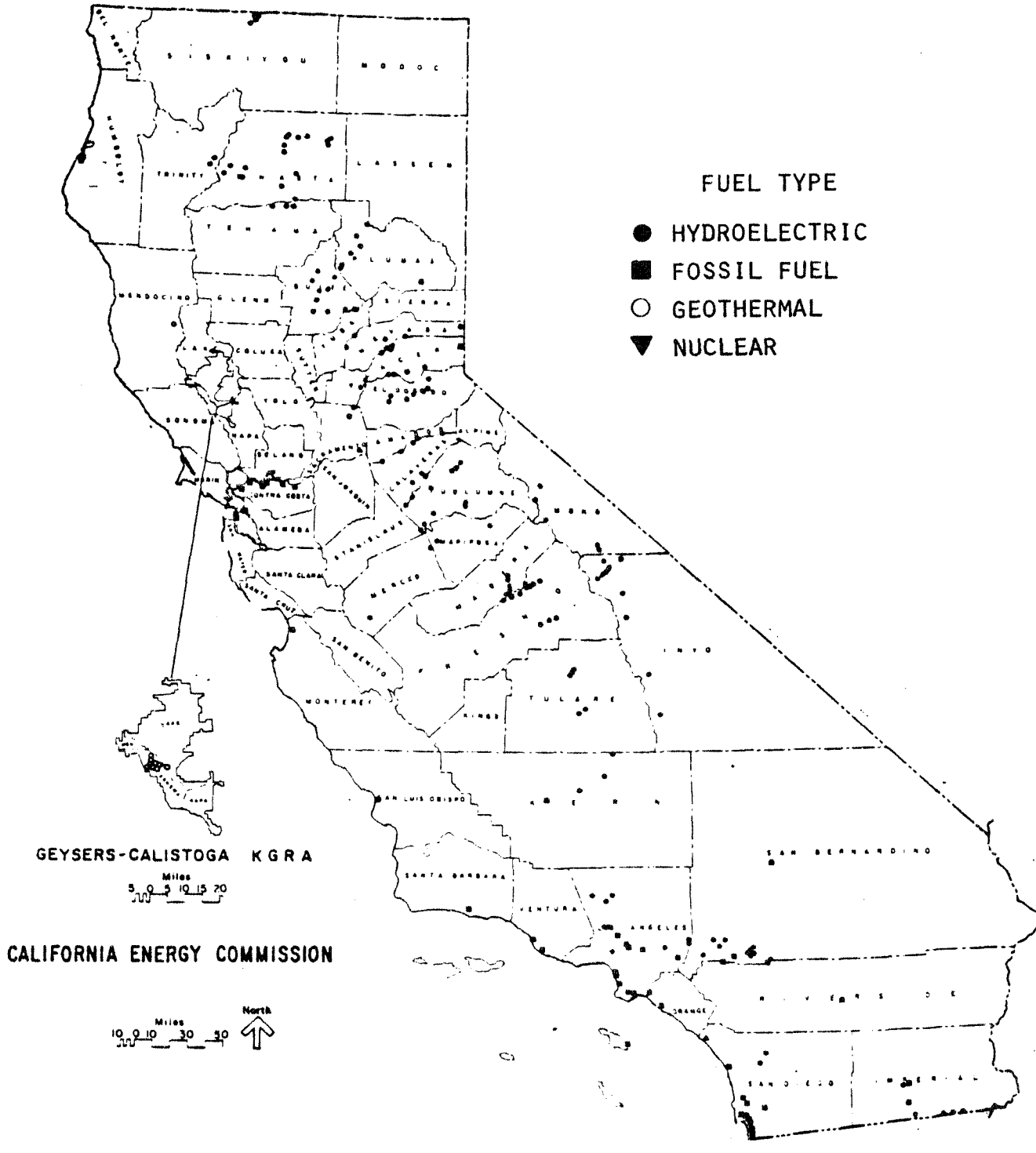
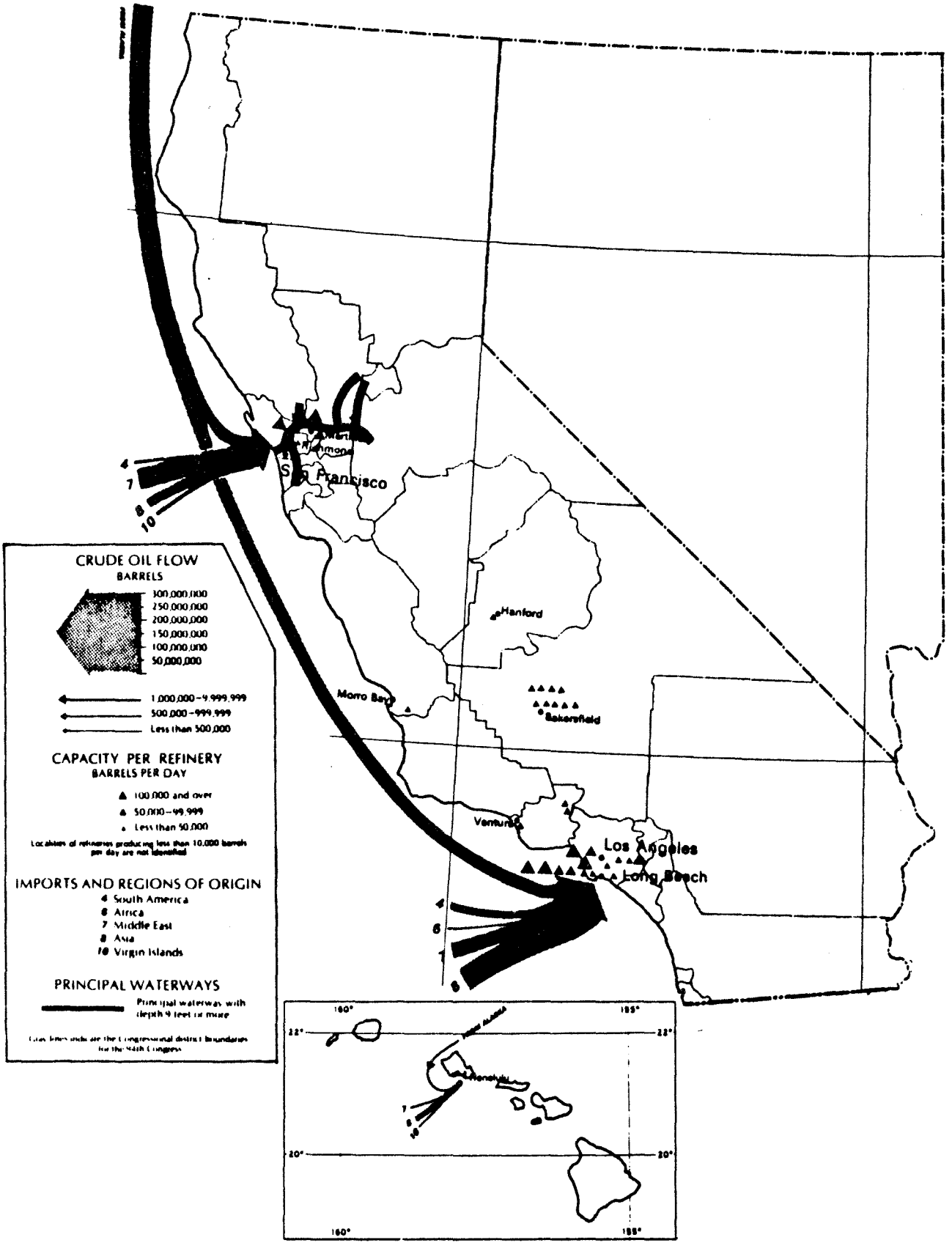
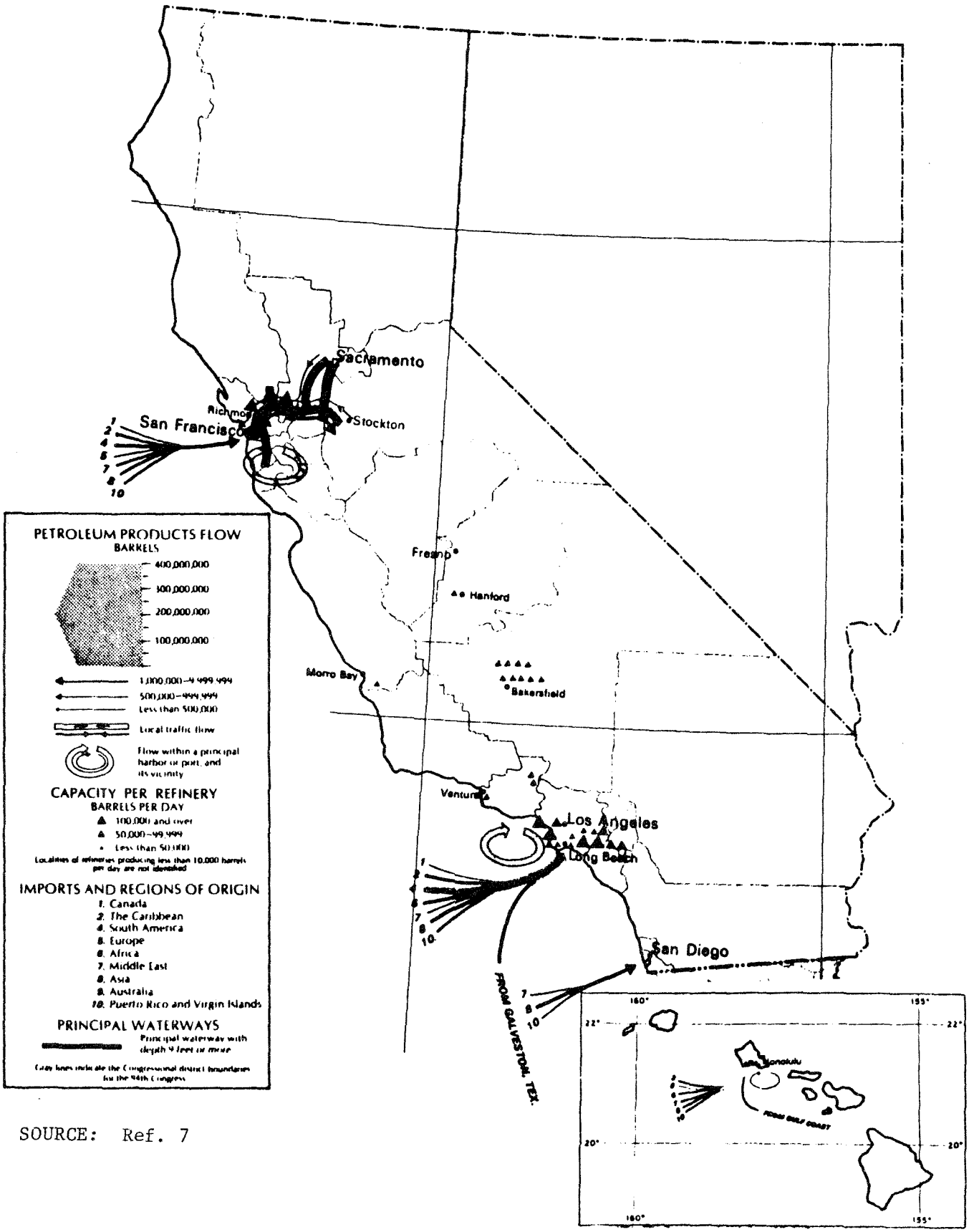


Figure 5-4. EXISTING ELECTRICAL GENERATING PLANTS - 1981



SOURCE: Ref. 7

Figure 5-5. TRANSPORTATION OF CRUDE OIL BY WATER, 1974



SOURCE: Ref. 7

Figure 5-6. TRANSPORTATION OF PETROLEUM PRODUCTS BY WATER, 1974

stocks may be considered. This does not seem likely, and the above information is presented primarily for completeness.

b. Tanker. Ocean-going vessels can be used to transport either liquid or solid freight. Consequently, their use may be considered for the conveyance of (1) coal from Alaska, (2) liquefied natural gas from Alaska or international sources, or (3) the methanol itself to California, if the production facility is located out of state. The off-loading of fluid fuels for California could utilize deep water single-point-mooring facilities. This would greatly facilitate the unloading problem and would allow sites not located near a harbor to be utilized. However, since the utilization of methanol even in applications such as centrally located utility power plants would not likely be sited in such a simple manner, it is quite probable that a means of trans-shipment would also be required.

Currently, 26,000 DWT (dead weight tons), 35,000 DWT, and 60,000 DWT tankers carry the majority of the coastal domestic petroleum tonnage. Gasoline is the major shipped good, with crude petroleum and other unfinished oils following in order of magnitude. The average tanker speed is 16.5 knots, and they require 24 to 36 hours to load and unload.

Since the cost per ton of operating an ocean-going tanker falls dramatically as its capacity increases, today's major fleets have seen an emphasis toward a greater number of vessels with larger payloads. These tankers are used primarily for the import of foreign crude oil, and they can range from 170,000 to 380,000 DWT. One major disadvantage of these super-efficient, mammoth-sized crafts is the substantial cost of the new facilities needed to handle them. They can approach few existing harbors due to their great draft.

Paralleling development of the crude oil supertanker has been that of the natural gas carrier. Sea transportation of liquefied natural gas (LNG) became a commercial reality in the 1950s, and this option must be considered for transporting under-utilized, remote natural gas as a potential feedstock for the production of methanol in California. Approximately 35,000 cubic feet of natural gas can be reduced to one barrel of LNG at minus 258°F, and 125,000 cubic meter LNG tankers are not uncommon. In the early 1970s, several investigators believed that it would be more economically advantageous to convert Persian Gulf natural gas to methanol for transport to the United States rather than liquefying it and using cryogenic LNG tankers. Even though the production of methanol for natural gas is less efficient, more expensive, and yields a product with a lower calorific value than LNG production, it was contended that the use of conventional tankers for methanol over long transport distances would provide a lower overall cost alternative. However, these estimates were based upon a cost of $.10 per million Btus for natural gas and the unproven assumption that existing, conventional oil tankers could be utilized for methanol transport. The breakeven distance after which methanol was perceived as the more economical choice, based upon these conditions, ranged from 4000 to 7000 nautical miles one-way. It was also acknowledged that escalation of gas prices would extend the distances for which LNG is more economic. Since the cost for natural gas has increased significantly from that used in these early estimates and it has not been shown that unmodified tankers can be used for conveying methanol without contamination problems, it

is unlikely that the use of remote natural gas on a feedstock for overseas methanol production is feasible for anything other than relatively small resources that cannot support LNG production facilities. In this instance, a barge or tanker mounted methanol plant could be moved from one site to another might be promising. It should also be noted that the siting of LNG offloading facilities in California has been a subject of political controversy and this issue must be resolved.

Regarding the transport of Alaskan coal to California for use as a feedstock, off-loading terminals with connections to existing major rail lines could be developed in conjunction with any of the developed port facilities in the state: Humboldt Bay, San Francisco Bay, the ports of Stockton and Sacramento, Moss Landing, Port Hueneme, and the Los Angeles, Long Beach, and San Diego harbors. However, to approach economic competitiveness with inland (Western) coal, it must be shipped in bulk carriers with capacities of 100,000 DWT or greater. The ports of Los Angeles and Long Beach have initiated programs to expand their coal terminal capabilities to handle 60 million tons annually by 1990. Additional dredging for the Los Angeles port to 65 feet has been proposed and approach channels for Long Beach already are more than 60 feet deep. Very large oil tankers which could be used for methanol can be loaded at Richmond in San Francisco Bay through the use of lighters; 100,000 DWT vessels must be partially unloaded before they can proceed to the Richmond oil unloading terminal. Typically, 100,000 DWT vessels have a draft of about 50 feet. Most ports in California have water depths sufficient for docking 16,500 DWT bulk carriers with a draft of about 31 feet, but not much more. The ports of Stockton and Sacramento are included in this category. The remaining developed ports at Crescent City, Fort Bragg, Bodega Bay, and Morro Bay have relatively shallow channels and do not have access to a major rail line (Ref. 10).

D. TRANSPORT COMPARISONS

Unfortunately, it is not possible to decide which transportation alternative is more advantageous without making a detailed analysis of the specific route, form of feedstock or fuel, and quantity of material to be conveyed. The reason for this is that these alternatives are very site-sensitive. Each mode differs in terms of the magnitude of its contribution to energy demand, its energy efficiency, the types of fuels it consumes, and the types of transportation needs it fulfills. However, some general guidelines can be provided and comparisons can be made between the various transport possibilities. This information is provided in the following material.

1. Cost

Even though the estimation of true economic costs of transporting energy materials by the existing modes is complicated by several factors, it is an undisputed fact that the cost of transportation can frequently account for more than 25% of the total delivered fuel price, and as much as 75% of the delivered price in some instances.

Since we must note the potential need for transporting both the feedstock material as well as the methanol itself, it is necessary to consider the conveyance of both solid and liquid freight. Therefore, information is presented that relates to both coal as well as crude oil and refined products.

In 1977, the annual coal usage in the United States was approximately 701 million tons (Ref. 5). This coal was transported by rail, water, truck, and slurry pipeline. The various methods of conveyance and their rankings by percent of total coal carried during 1977, as well as the comparative approximate model costs per ton-mile, are presented in Table 5-4.

In 1977, approximately 643 million tons of crude oil and 1,439 million tons of refined petroleum products were transported in the United States (Ref. 5). This material was hauled by rail, water, truck, and pipeline. The various methods of conveyance and their rankings by percent of material carried during 1977 as well as the comparative approximate model costs per 100 barrel miles are presented in Table 5-5.

The waterway system is currently the most economic means of transport available for most commodities. However, this system does not serve the Western region to an extent that it can be considered a viable option for California, with the possible exception of those scenarios taking advantage of Alaskan or foreign feedstocks. The trucking industry is not cost-competitive with either the railroads or pipelines for the type of high-volume, long-distance traffic which will result in many situations. The use of trucks via the highway system, even though commonly restricted to short hauls and as a method of transfer, will undoubtedly play an indispensable role for distributing methanol used in the automotive demand market.

It should also be mentioned that while costs vary considerably, electric transmission is generally competitive with rail or pipeline for distances of up to 500-600 miles. Beyond that point, rail and pipeline costs increase at a slower rate than electric transmission costs.

Federal policies can obviously have a substantial effect on relative pricing advantages through differing tax advantages and subsidies. Furthermore, the figures presented previously do not include an element of public subsidy for barges and trucks in the form of government highway and waterway expenditures.

2. Energy Intensity

While the choice of the transport subsystem(s) to be used will likely be chosen by economic factors, one of the prime economic drivers is the energy intensity of the conveyance itself. This is assuming, of course, that equipment for hauling the material exists and operating costs are, therefore, the most significant variable. In order to provide some insight into this area, Table 5-6 lists the amount of energy necessary to transport one ton of freight one mile by various means of conveyance.

Table 5-4. 1977 U.S. COAL TRANSPORTATION

TRANSPORTATION MODE	PERCENT OF TOTAL COAL TRANSPORTED	AVERAGE COST PER TON-MILE
Rail	59.1	$ .017
Truck	18.0	$ .084
Water	22.3	$ .007
Slurry Pipeline	0.6	$ .017

Source: Ref. 5

Table 5-5. 1977 U.S. CRUDE OIL AND REFINED PETROLEUM TRANSPORTATION

TRANSPORTATION MODE	PERCENT OF CRUDE OIL TRANSPORTED	PERCENT OF REFINED PERTROLEUM PRODUCT TRANSPORTED	AVERAGE ('81$) COST PER 100 bbl-miles
Pipeline	72.5	36.6	$ .09
Truck	14.0	36.5	$ .92
Water	13.2	25.1	
Tanker			$ .05
Barge			$ .15
Rail	0.3	1.8	$ .54

Source: Ref. 5

Table 5-6. ENERGY INTENSITY BY TRANSPORTATION MODE

TRANSPORT MODE	ENERGY INTENSITY* (Btu/ton-mile)
Truck	2,500
Rail	680
Air	12,030
Marine	
Coastal	380
Ocean	590
Pipeline	
Natural Gas	2,000
Crude Oil	300
Petroleum	400
Coal-Water Slurry	4,200

* The quantity of energy necessary to convey one ton of freight a mile.

Source: Refs. 12 & 14

E. STORAGE AND DISTRIBUTION

The technology to be used for distributing methanol is adequately covered in Section C by the presentation of the various transport options. However, some pertinent issues relating to the storage and distribution of methanol merit being addressed separately.

1. Utility Applications

Design of a fuel system for utility central stations can be divided into two segments. The first includes equipment needed to transfer fuel from the transport vehicle to a storage tank or the day tank; the second, the equipment to pump it from storage, or from the day tank, to the burners.

Additional expense would be required for storage and a distribution system for methanol firing. It has been estimated by the U.S. Office of Technology Assessment that the distribution system could require storage tanks and pumps costing about $700 per barrel per day of throughput. Because of the solvent nature of methanol, independent storage, piping, pumps, etc., would have to be provided to segregate methanol from any conventional fuel oil

system. Problems might occur from dislocation of deposited hydrocarbons and dirt if a common oil-methanol system is used. Furthermore, the low viscosity and low heating value of methanol would, in most cases, dictate separate burner orifices and a separate feed pump of twice the usual size. Tighter standards on valve packing, etc., will be required to prevent leaks of this low-viscosity fuel.

Sizing of the storage tank or tanks is not as easy as it seems. Storage capacity, including a safe-inventory margin, depends primarily on the rate of fuel consumption, method of delivery, and the distance from the supply depot to the plant. Several other factors such as delivery delays, strikes, fuel shortages, etc., must also be considered. In general, industry practice had been to inventory a 60- to 90-day supply of fuel in the storage tanks. Unstable market conditions would dictate even greater storage capacity to ensure continuous plant operation.

As previously mentioned, the type of delivery carrier depends on the rate of consumption and the location of the consumer, as well as the issue of concentrated versus dispersed utilization, i.e., automotive or utility applications. For example, if the user is large, and it can accommodate barge or tanker delivery, water transport should be considered seriously--delivery costs are lowest for this method. If the rate of consumption is low, truck delivery is more practical than shipment via rail, pipeline, or water. When receipt is by truck, the storage tank should be large enough to take advantage of bulk prices, or full truckloads, normally 5000 to 10,000 gallons, since prices are higher for partial loads.

Tank location is another important factor to consider. It should be close to both the unloading area and to the point of use to minimize pipeline installation and operating costs. These objectives, however, are often difficult to achieve for large tanks. For example, sufficient space must be available for safety dikes, in case of spills from storage tanks, and tanks must be built away from buildings, hazardous equipment and materials, and power lines. Twenty-thousand (and in some cases up to 60,000) gallon tanks are usually buried and present no space problems.

The safety dikes around storage tanks, particularly the common earthen type, require considerable area. For a one million gallon tank, a square dike would have to be about 6 feet high, 21 feet wide at the case, 3 feet wide at the top, and 180 feet long on each side. Where space is limited, concrete dikes can be used, or a steel shell can be erected around the storage tank. These alternatives, however, are expensive.

The high volatility of methanol (similar to gasoline) would necessitate the use of either closed floating-roof or conservation-type storage tanks to reduce evaporation losses and pollution as well as rainwater contamination. Above-ground steel tanks with fixed or floating roofs should be designed in accordance with American Petroleum Institute (API) standards. Tank cleanliness and water contamination are significant concerns regarding methanol storage, and the elimination of water is frequently difficult to ensure since tank bottoms can settle and flex under varying load conditions. If water contaminates methanol, it is virtually impossible to remove. However, in neat applications, water is not as great a concern as with blended applications.

The question of tank cost and fuel vaporization losses are dealt with in the stationary utilization portion of this report. Small underground tanks generally are fabricated of steel, but fiberglass tanks in sizes up to 20,000 gallon capacity are available. Obviously, fiberglass tanks are suitable for low viscosity fuels such as methanol that do not require heating, and then only where material compatibility of methanol with the particular composition of fiberglass used is assured.

When there is a considerable distance between the storage tank and the point of use, it is sometimes practical for the utilities to install a day tank near the boiler. Among its advantages is the elimination of long burner-return lines back to the storage tank. The day tank, which can be either above or below ground is filled from the main storage tank or directly from the transport vehicle; fuel is pumped from it to the burners. However, with the low viscosity properties of methanol, the use of day tanks should not be considered a necessity.

Pipelines may be above or below ground, depending on the terrain and site congestion. Above-ground lines (1) are easier to install, (2) provide a visual observation of its condition, and (3) are easy to maintain. They can be at ground level, supported by piers, or suspended. Overhead lines, however, are far more costly.

Underground pipelines generally are buried in the soil. But in some cases, such as when line inspection and maintenance or valving make it necessary, they are placed in a culvert or trench with other lines.

Cathodic protection of buried piping is a big help in preventing external corrosion. Coatings can protect where they are unbroken, but damage to the coating leaves bare metal susceptible to pitting. Cathodic protection can come from graphite or magnesium anodes that direct current to base metal, making that metal a cathodic area and preventing it from corroding. Magnesium anodes (giving galvanic protection) need no external source of current, but are slowly consumed while they protect. A wire connects each anode to the pipe. Graphite anodes (electrolytic protection) are not consumed, but they must be energized by an external source of current, rectified to DC.

2. Automotive Applications

The aspects of storing and distributing methanol to be used for the needs of the automotive market will undoubtedly be handled in a manner very much like that currently done for gasoline. Much of the technology described previously relating to utility applications will also be applicable to the automotive area as well.

The local distribution to the widely dispersed service stations located throughout the state will likely be satisfied by standard tank trucks with a 9,200 gallon capacity. If methanol is used as a neat fuel, separate storage tanks and pumps will be required at the service station.

Because of the lower specific energy (Btu/gallon) of methanol, approximately twice the volume and mass will be necessary to store the same amount of

energy as a petroleum fuel. The typical gasoline service station storage tank has a 10,000 gallon capacity with three tanks at one location being typical. Since the cost of storage tanks has a direct correlation to the surface area of the tank and, consequently, the tank volume to the 2/3 power, methanol storage tanks for an equivalent energy content will cost about 1.6 times as much as those for petroleum. The consumption of twice as much fuel would mandate that the station pump operation, tank truck deliveries, etc., would all be double what they would be for an energy equivalent quantity of gasoline.

F. HAZARDS AND PROBLEMS

Since methanol is a volatile, strongly polar alcohol, difficulties of many types may be encountered during its transportation and storage. The hazards can be of a nature to affect the environment, the health of those exposed to the methanol, the materials it contacts, or cause contamination of the methanol itself. These areas are briefly addressed, not in an attempt to provide a comprehensive description, but rather to highlight anticipated concerns.

1. Health

Methanol is a toxic substance and comes under the regulation of the Federal Hazardous Substances Act. Serious consequences to an individual can result if adequate means for prevention and protection from the potential dangers are not taken. The effects of methanol exposure can be immediate as well as of a long-range accumulative nature. Exposure time as well as the individual's personal tolerance influence the severity of the symptoms.

Methanol damages the central nervous system and has the most obvious effect on the optic nerve. This can cause a strong sensitivity to light and temporary or permanent blindness. Muscular effects can result in addition to progressive degenerative damage to the heart, liver, kidneys, and other organs. Methanol is released very slowly from the body and many of the effects are thought to result from the formaldehyde or formic acid which are considerably more toxic than the methanol.

Exposure to methanol can result from ingestion, inhalation, dermal contact, or exposure to the eyes. Direct ingestion of methanol causes the most rapid response, but high concentrations of methanol vapors can also result in acute poisoning after brief exposures. Methanol can be absorbed through the skin and cause all of the toxic and lethal effects that result from the other types of contact. Regarding contact with the eyes, the visual symptoms may sometimes clear up but later return to cause blindness.

2. Environmental

Primary environmental considerations are the air pollution resulting from combustion of methanol, fugitive emissions from methanol storage and handling, and the potential problems of large-scale spills. The issue of pollutants from methanol combustion is dealt with in the utilization sections of this report.

The photochemical reactivity of methanol is low in comparison to the evaporated constraints of most petroleum based fuels (see Chapter 6). Therefore, fugitive emissions from methanol storage and handling contribute to urban air quality degradation to a lesser extent than petroleum products.

Fugitive emissions can be expected during the various phases of loading, unloading, and storage of the methanol from the storage tanks at the bulk station, during loading and transit, and at the utilization tank. As stated in the Fuel Utilization--Stationary Applications section of this report, "Since methanol has a significantly higher vapor pressue than distillate fuel oils (96 mm Hg vs. 0.1 mm Hg at 68°F), vaporization losses to the atmosphere could be significant if proper precautions are not taken. During the SCE test, it was estimated that 8-10 gal per day of methanol were lost due to evaporation. The loss was blamed on a faulty sealing between the floating roof and the walls of the floating roof methanol storage tank. Examination of the interior of the tank at the end of the test showed that almost 3 inches of area between the floating roof assembly and the tank wall around the circumference of the tank were exposed to the atmosphere. The loss of 8-10 gal per day represents about a 0.05% loss of total methanol." However, in comparison to gasoline, methanol has a lower vapor pressure, therefore fugitive emissions would be expected to be less. Furthermore, in a survey done by Badger Plants, it was found that the expected emissions from methanol storage and handling at a ton/day plant were estimated at 60 lb/hr. as methanol.

3. Physical

Obviously, the most serious physical hazard is that of explosion or combustion of the methanol. A mixture of 6% to 36% methanol by volume in air is flammable at standard temperature and pressue. Furthermore, air at ambient conditions (68°F) that is saturated with methanol vapor contains 13 percent methanol and is therefore explosive. By comparison, air saturated with gasoline is too rich to explode.

Also of significant concern is the question of material compatibility with methanol. Noticeable corrosion has been reported by many concerning methanol in contact with terneplated (lead and tin plated) automotive fuel tanks. The reactive polar hydroxyl group present in methanol differs significantly from petroleum hydrocarbons in its corrosive effects on metals. This factor is seriously compounded if water and salts are also dissolved in the fuel. Severe corrosion has been experienced with zinc, lead, and magnesium in contact with methanol. Aluminum and copper are also more susceptible to corrosion by methanol than by hydrocarbons. All of the previously mentioned materials should be coated or lined with inert or resistant coatings. However, dry methanol could be stored in conventional steel tanks without excessive difficulty. Even here, though, the possibility of galvanic attack should be thoroughly investigated prior to using rust-preventative paints and coatings.

Methanol acts as a strong solvent. Consequently, many plastics and rubbers that are commonly used as gaskets or floats in conventional petroleum distillate fuel systems can experience swelling or softening. Polyamides and methacrylate are thus affected and "viton" floats can experience swell up to

50 percent. However, polyethylene and polyacetol seals do appear to be compatible with methanol usage.

G. NEAR-TERM SUPPLY CONCLUSIONS

It has been estimated that a realistic near-term methanol transition in California would probably result in the consumption of 10,000 to 100,000 barrels of methanol per month. This limited usage would not be sufficient to justify the construction or use of a dedicated pipeline for the transport of the methanol, even if all the usage was centrally located and not dispersed. Even a relatively small 8-inch diameter pipeline would carry about 40,000 barrels per day. Rather than using a dedicated pipeline, another option would be to transport batches of methanol in existing petroleum pipelines. This is a concept that requires further study to ascertain that the issues of water pick-up, color degradation, material compatibility, and absorption of normal pipeline residues do not create insurmountable difficulties. It should also be noted that there is a rather limited existing pipeline network into California as compared with other portions of the country. Furthermore, the conveyance of sufficient methanol to satisfy the high end of this demand range (100,000 barrels per month) would probably not be handled via ship. As illustrated in Table 5-7, a 105,000 DWT tanker could deliver 768,000 barrels of methanol and it is unlikely that a 7-1/2 month supply of fuel would be desirable.

By perusing Table 5-8, it appears obvious that the most likely candidates for the near-term transport of methanol in California are track, rail, and barge. The truck method of transport is viable only for the low end of the demand range (10,000 barrels per month), where about 1.5 truck deliveries per day could satisfy this requirement. However, as previously discussed, this is probably not a cost-effective approach and would most likely be utilized only for handling dispersed distribution. Probably, the 10,000 barrel per month methanol demand would not be efficiently and economically satisfied by either 14 rail tank cars or one barge delivery per month. The choice of transport mode would first be decided by utilization site: that is, does it have access to barge delivery or is rail delivery more convenient? If both options are available, then individual transport price negotiations with the potential carriers would be the deciding factor. Based upon past experience, barge delivery would probably be more economic if it is an available option.

For the high-end of the near-term demand range (100,000 barrels per month), the quantities of methanol required would be so great as to preclude the use of truck delivery for anything other than limited dispersed distribution requirements. Again, rail and barge conveyance are the most likely contenders. In this case, 1.4 unit trains of 100 tank cars each or 1.7 tows of 4 barges each would be required to transport 100,000 barrels of methanol per month. The same considerations previously described would decide which of these options is more favorable.

In conclusion, corrosion, water free distribution, flammability, and careful handling procedures in light of methanol's toxicity are the main difficulties to be overcome.

Table 5-7. METHANOL DELIVERY CAPACITY OF VARIOUS TRANSPORT MODES

TRANSPORT MODE	CARGO CAPACITY (barrels)
TRUCK	220
RAIL TANK CAR	710
BARGE	9,400
SHIP (105,000 DWT)	768,000
PIPELINE (8 inch diameter)	40,200 per day

Table 5-8. QUANTITY OF METHANOL DELIVERIES REQUIRED BY VARIOUS TRANSPORT MODES FOR NEAR-TERM USAGE

TRANSPORT MODE	NUMBER OF DELIVERIES PER MONTH	
	10,000 barrels/month	100,000 barrels/month
TRUCK	45.5	455
RAIL TANK CAR	14.1	141
RAIL TANK TRAIN (100 tank cars)	.14	1.4
BARGE	1.1	11
TOW (4 barges)	.27	2.7
SHIP (105,000 DWT)	.013	.13
PIPELINE (8 inch diameter)	.008	.08

H. TRANSITIONAL FACTORS FOR TRANSPORT AND DISTRIBUTION TO CALIFORNIA SUBMARKETS

The transition from the use of conventional petroleum-based fuels in California submarkets to methanol-based fuels may pose economic, technical, and institutional difficulties to both the suppliers and the users of the methanol fuel. This section will examine some of the transport, distribution, and storage aspects from a California-specific, submarket-specific perspective. The three California submarkets chosen for this analysis are: methanol/gasoline blends, neat methanol fuel for automobiles, and electrical utilities. In the transitional phase to methanol utilization, the only meaningful source of supply for California (as described in Chapter 4) is remote natural gas-based methanol plants, most likely from coastal Alaska. As previously discussed in this chapter, the supply of methanol to California from such locations does not produce insurmountable problems. However, the distribution and transportation of methanol and/or methanol-gasoline blends within the State of California to the specific submarket users may face significant barriers. For example: water commonly found in petroleum product distribution systems may cause gasoline blends transported or stored in those systems to absorb water and phase-separate, most likely in a customer's automobile gasoline tank. Another example of potential transitional problems for the methanol use in automobiles is the methanol incompatibility of fiberglass service station storage tanks.

1. Transport and Distribution of Methanol Gasoline Blends in California

Methanol and a cosolvent can be blended with gasoline for octane number enhancement or, if methanol and the cosolvent is less expensive than gasoline, as a volumetric enhancer. Two properties of methanol/cosolvent gasoline blends can impact its storage and distribution in California: (1) When mixed with gasoline, methanol causes the vapor pressure to increase (the apparent volumetric blending RVP increases as the concentration decreases) and, if there exists too much water and/or too low a temperature, the blended product can phase-separate into a gasoline phase and a methanol-water phase.

If a methanol-containing gasoline with a 9 pound RVP is comingled with another gasoline, also at 9 pounds RVP, the result of the blended gasoline could exceed the RVP limit set by California Air Quality law. Such a gasoline could not be legally sold in California and action would have to be taken to reduce the vapor pressure. In addition, a condition on the waiver which was granted a recent waiver application under Section 211F of the Clean Air Act states that reasonable precautions (be taken) to ensure that the finished unleaded gasoline is not used as a base gasoline to which other oxinates are added. Furthermore, pipeline operators may not view a methanol-containing blend as a fungible product and other petroleum companies may not view such gasolines as appropriate for entry into exchanges. The clear implication of these factors is that methanol containing gasoline blends must be both segregated and identified. Such factors may also limit or preclude the use of petroleum product pipelines for the transportation of methanol containing blends unless such pipeline is owned or operated by the producer of the methanol-containing fuel. Discussions with one california petroleum pipeline company revealed that they would accept methanol gasoline blends for shipment

in their system, however, product specifications could not be guaranteed. Sufficient water was believed to be present to make phase separation during shipment very likely. Conversly, ARCO has successfully expressed test batches in their pipeline from Philadelphia to Pittsburg.

The methanol-gasoline blend can phase-separate in the presence of water. The temperature at which such phase separation can occur is determined by the relative proportions of water methanol and cosolvent, in addition to the characteristics of the gasoline. The addition of a cosolvent significantly improves the water tolerance of methanol-gasoline blends. Figure 5-7 taken from the ARCO waiver application shows this relationship. Reaching from the refinery to the fuel tank on the vehicle, the transportation/distribution/ storage system for methanol-blended gasoline in California must be such that the gasoline-methanol blend is never exposed to or collects water in excess of the cosolvent's ability to maintain the water in solution.

Because the available cosolvents are either of limited supply, such as gasoline-grade tertiary butylalcohol, or expensive, such as propanols, a refiner or distributor would wish to blend the minimum amount of cosolvent

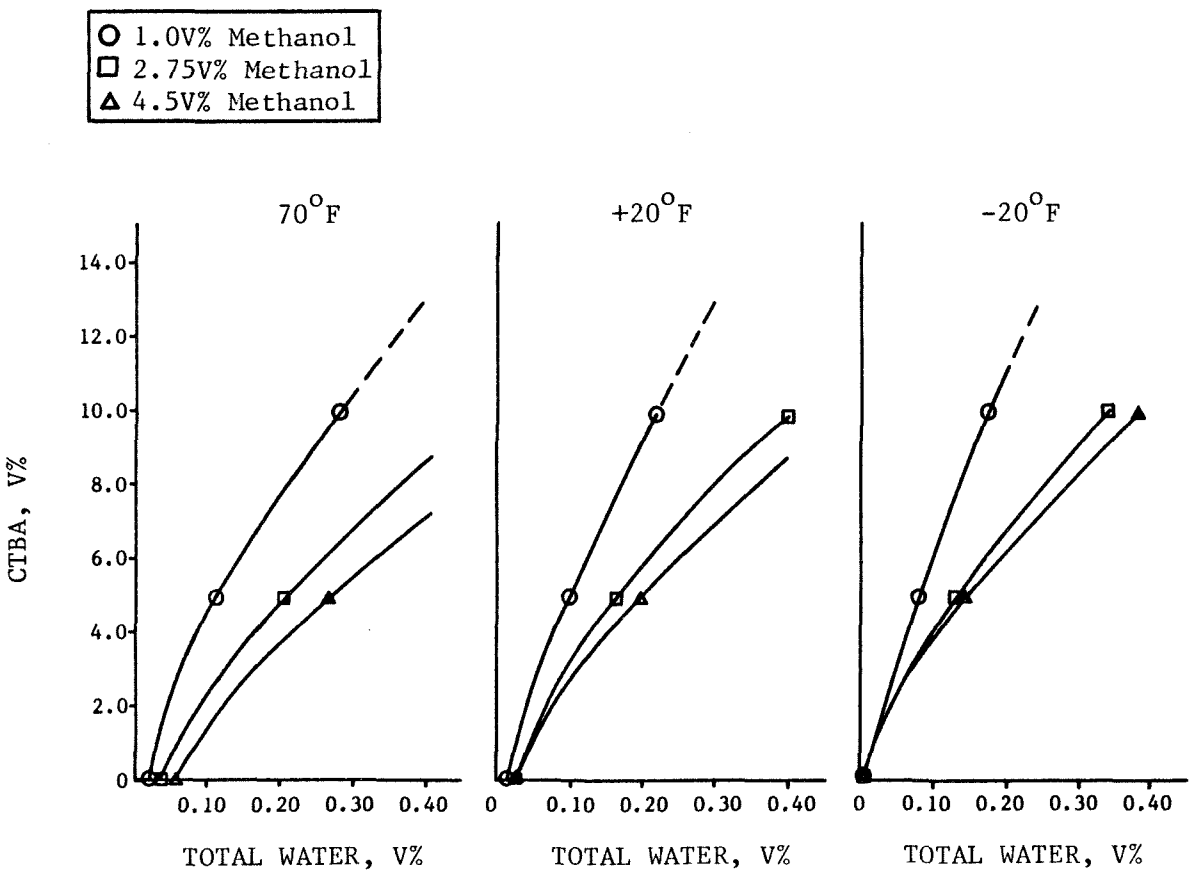


Figure 5-7. WATER TOLERANCE OF FUELS CONTAINING METHANOL AND GTBA

consistent with vapor pressure and water tolerance requirements. Such a minimization involves the consideration of four basic factors:

(1) The expected amount of water present.

(2) The minimum temperature that blended gasoline is expected to be subject to.

(3) The composition of the gasoline used for blending.

(4) The amount and proportions of methanol and cosolvent used.

Before the methanol reaches the point of being blended with gasoline, it can potentially absorb water from several sources, including atmospheric absorption if exposed to air, water bottoms present in tankers, and water intrusion if it is being shipped on a single-hull vessel. Water can enter the gasoline system through many sources, but usually settles out as water bottoms in storage tanks at the refinery or at the service station underground tank. Union Oil, in a study for the U.S. Department of Energy (Ref. 23), performed measurements on their systems to provide a statistical distribution of the size of water bottoms present in both the storage tanks and service station tanks. These data are presented in Figure 5-8. As can be seen from the figure, gasoline storage tanks have significantly greater water bottoms than service station storage tanks.

To ensure that the blended gasoline will not separate in a customer's gas tank, the amount of water initially present in the transport storage and distribution system has to be reduced to an acceptable level, and the water entering the system has to be reduced to an acceptable rate. If the initial de-watering of the system is not wholly successful, the initial batch of methanol-gasoline blend can phase-separate. The gasoline-phase can most likely be returned to the gasoline pool for reblending. However, the methanol water phase (containing some gasoline components) poses a more significant problem. If such a separated phase is classified as a hazardous or toxic waste, the disposal options are severely limited in California due to the lack of licensed liquid waste disposal sites. Therefore, the options to the refiner are either to store it at a refinery site or to incinerate it as a recycled fuel.

If the system has been successfully de-watered or is originally sufficiently dry, the second area of concern is the rate at which new water can enter into the system. Under the assumption that rain water falling upon gasoline storage tanks is the dominant point of entry of water into the system, Union Oil (Ref. 23), has calculated the rate at which rain water can enter the gasoline stored in a single-seal, uncovered floating-roof product storage tank. The use of this rate to calculate phase-separation potential for methanol gasoline blends is subject to some significant caveats: (1) rain water flowing down the sides of a storage tank may not be the dominant source of water entry into the system, and (2) the water drain systems used on such tanks are not always effective and could present a much higher source of water intrusion than rain water flowing down the sides of the tanks. (Presumably, such drain systems would be subject to more frequent maintenance and inspection with a methanol-blended gasoline present.)

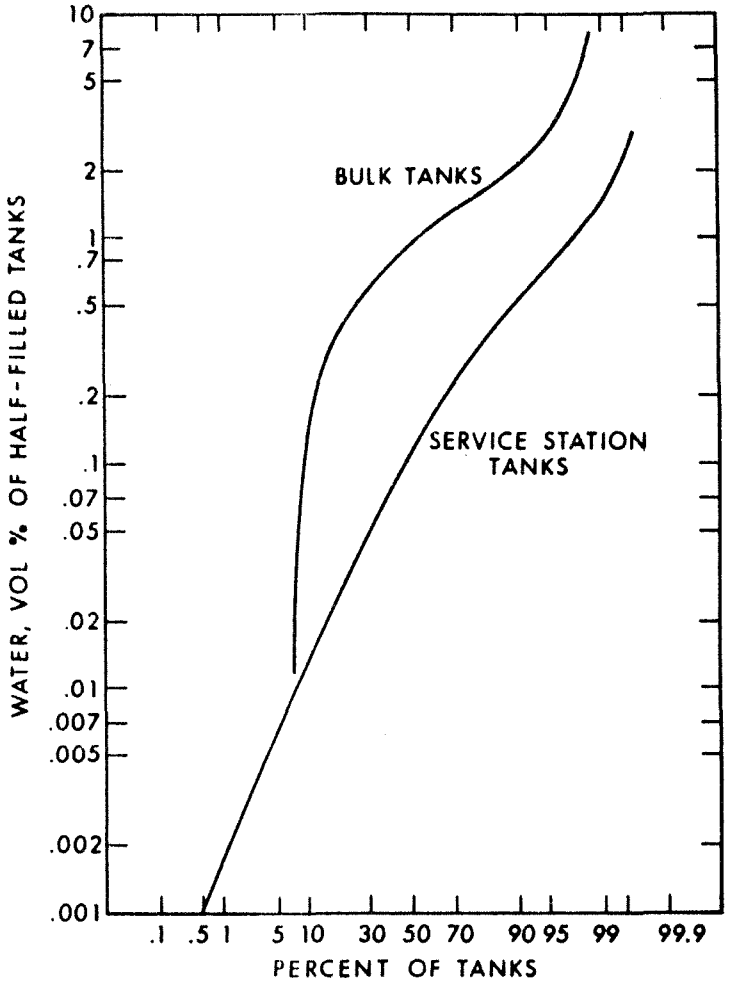


Figure 5-8. OCCURRENCE OF WATER IN GASOLINE DISTRIBUTION SYSTEM TANKS

There are a few tanks in California that are covered. If these tanks were chosen for storage of methanol gasoline blends, the water entry rate would be significantly lower than that calculated. Also, double-sealed floating roofs used to meet stationary source requirements would significantly reduce the water intrusion. Another possibility is that the methanol and cosolvents can be blended upon leaving the product storage tanks rather than upon entry.

Under the assumption that gasoline is stored for approximately 5 weeks in the product storage tanks, the Union Oil estimate of rain water entry rate can be combined with the NOAA 30-year average rainfall data to calculate the amount of water which would enter the gasoline. Figure 5-9 shows the percent concentration of water as a function of month-of-the-year for both the Los Angeles area and the San Francisco Bay area.

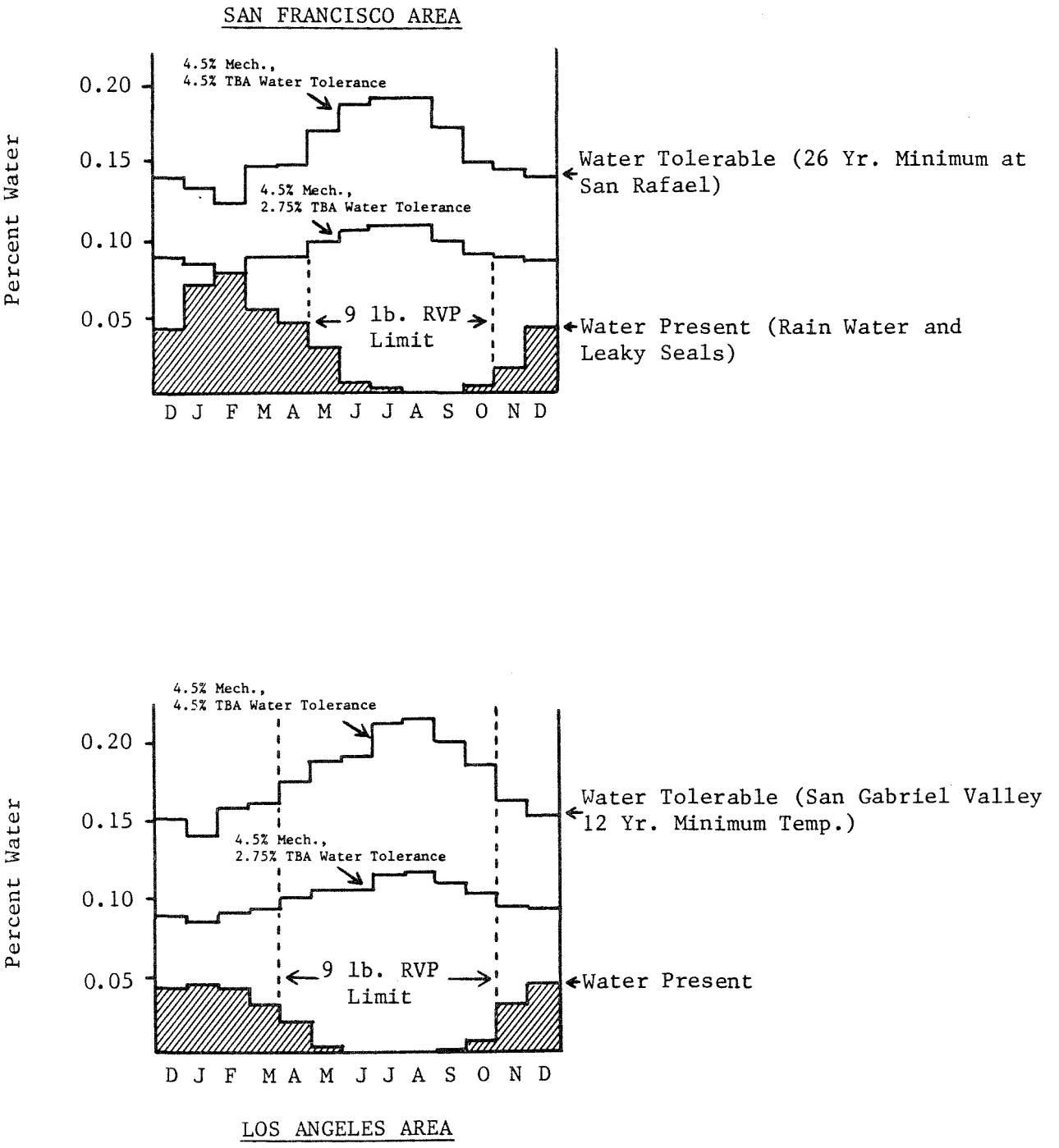


Figure 5-9. POSSIBLE WATER CONCENTRATION AND WATER TOLERANCES FOR METHANOL GASOLINE BLENDS

Likewise, the phase-separation data of methanol/TBA/gasoline blends from the ARCO Waiver Application can be combined with monthly low temperature data to estimate the water tolerance of such blends. The low temperature estimator to use for these two regions is problematic. A vehicle can be fueled in either area and driven to high-altitude mountain conditions in the middle of winter. Additionally, the lowest temperature recorded in any given month varies appreciably year-to-year. The estimator chosen for the Los Angeles area was the 12-year low temperature at the Burbank Airport, which would represent the low temperature in the San Fernando Valley area. For the San Francisco region, the low temperature over a 30-year period in the San Raphael area was chosen. Assuming a 4.5% methanol, 4.5% TBA blend, the water tolerance is shown in Figure 5-9 by the upper line. Given the sizable set of assumptions and caveats, it appears that the phase separation should not be a problem in either area at this concentration. The lower line shows the water tolerance of a 4.5% methanol to 2.5% TBA blend. Under these assumptions, its reduced water tolerance shows it to be marginal for the San Francisco Bay area and still acceptable in the Los Angeles area. It should be noted that the 9-pound RVP restriction which negatively impacts the methanol-blending economics occurs in both areas during the driest and warmest part of the year, which--from the standpoint of phase separation--would be the most attractive period of time.

In summary, it appears that reduced cosolvent below that currently allowed by waiver applications is a possibility at least in some portions of California and for some periods of the year from the standpoint of phase separation. The shipment of methanol within California by means other than pipelines is most likely a requirement. The warmer, dryer southern part of the state is probably a more attractive location for initial marketing than the cooler, wetter north. The cost advantage of the methanol-gasoline blends combined with their projected volume must be sufficient to overcome both the front-end cost of de-watering the transport and storage system and, also, the risk associated with a phase-separated batch.

2. Distributional Aspects of Transitions to Neat Methanol Automotive Fuel

Most of the considerations previously applied to the transport of neat methanol into California also apply for the transport of methanol within the State of California during the transitional phase. To briefly recap, train tankcars, trucks, barges, and small tankers can and, in many cases, currently do ship methanol, and these means could be readily used at any time to ship methanol within the State of California (although some materials modifications may be required). The steel tanks and steel pipes used at refinery and blending operations are, in principle, compatible with neat methanol and could be used without insurmountable problems. However, there are two areas that could cause barriers during the transition to neat-methanol fuel. These are: (1) the pipeline shipment of neat methanol batches; and (2) the storage of neat methanol at service station underground tanks.

Unlike other parts of the United States, much of the population of California is not dependent upon petroleum product pipelines for gasoline. Much of the population and VMTs are close to ports and refineries. During

the transitional period, by definition, methanol demand will be relatively modest and, hence, if any methanol was shipped by pipeline within the state, one would expect such batches to be relatively small and relatively infrequent. In such a situation, it would be very difficult to maintain adequate product specifications on the output side of the pipeline system, since the methanol would tend to pick up most of the water, sludge, gum, and surface deposits in the pipeline. This is not to imply that such shipments of methanol are not possible; in fact, the Williams Pipeline Company has run experimental tests sending a batch of approximately 5000 barrels of ethanol from Kansas City to Des Moines. To quote from the conclusion of the Williams test (Ref. 24):

> "In summary, our experimental pipeline test indicates that fuel-grade ethanol can be successfully transported in a multi-products pipeline system under controlled conditions. The greater the frequency of the batches through any given line segment, the fewer the quality problems that we would expect to experience."

Currently, almost all service station storage tanks installed in the State of California are fiberglass. The principal reason for this is the relatively short life or uncertainty of the lifetime of steel storage tanks. In California, the steel tanks last roughly 5 to 10 years, whereas a fiberglass tank can have an expected life of 20 years or greater. The fiberglass tanks are somewhat more expensive to install. For example, at a two-island, three-fuel grade service station, the 1981 dollar cost to replace three 10,000 gallon underground tanks and the lines to the two islands is approximately $60,000 for fiberglass and $45,000 for steel. To replace one tank with a steel tank and, in addition, to put steel lines to both islands costs approximately $20,000. In the period of time in which methanol could become economically viable transportation fuel in California (roughly the early to mid-90s) almost all the service station storage tanks will be incompatible with methanol fuel.

For methanol vehicles to be successfully introduced, some initial fuel supply infrastructure would have to be in place. The magnitude of that initial infrastructure is of importance to transitions to neat methanol fuel because it represents the "up-front," initial cost or investment necessary by energy companies to establish that infrastructure. As a very approximate benchmark, the diesel fuel retail availability before the marked growth in both diesel car sales and methanol retail availability can be used as an estimator for the required retail methanol availability. Such a number should be used with caution because the analogy between diesel and methanol is far from perfect. For example, 1992 methanol cars would not be expected to have the same attributes as 1972 Mercedes or Peugeots. Additionally, the location of the methanol service stations would probably not be the same as the diesel service stations.

For the period of time from 1976 to 1982, Figure 5-10 shows the percent of retail outlets carrying diesel fuel, the percent of new car sales which were diesel cars, and the estimated percent of vehicle population which was diesel. The data for the growth in retail diesel availability in LA County was obtained by sampling the fuel pump inspection certificates of the LA County Department of Weights and Measures. The sales of diesel automobiles in

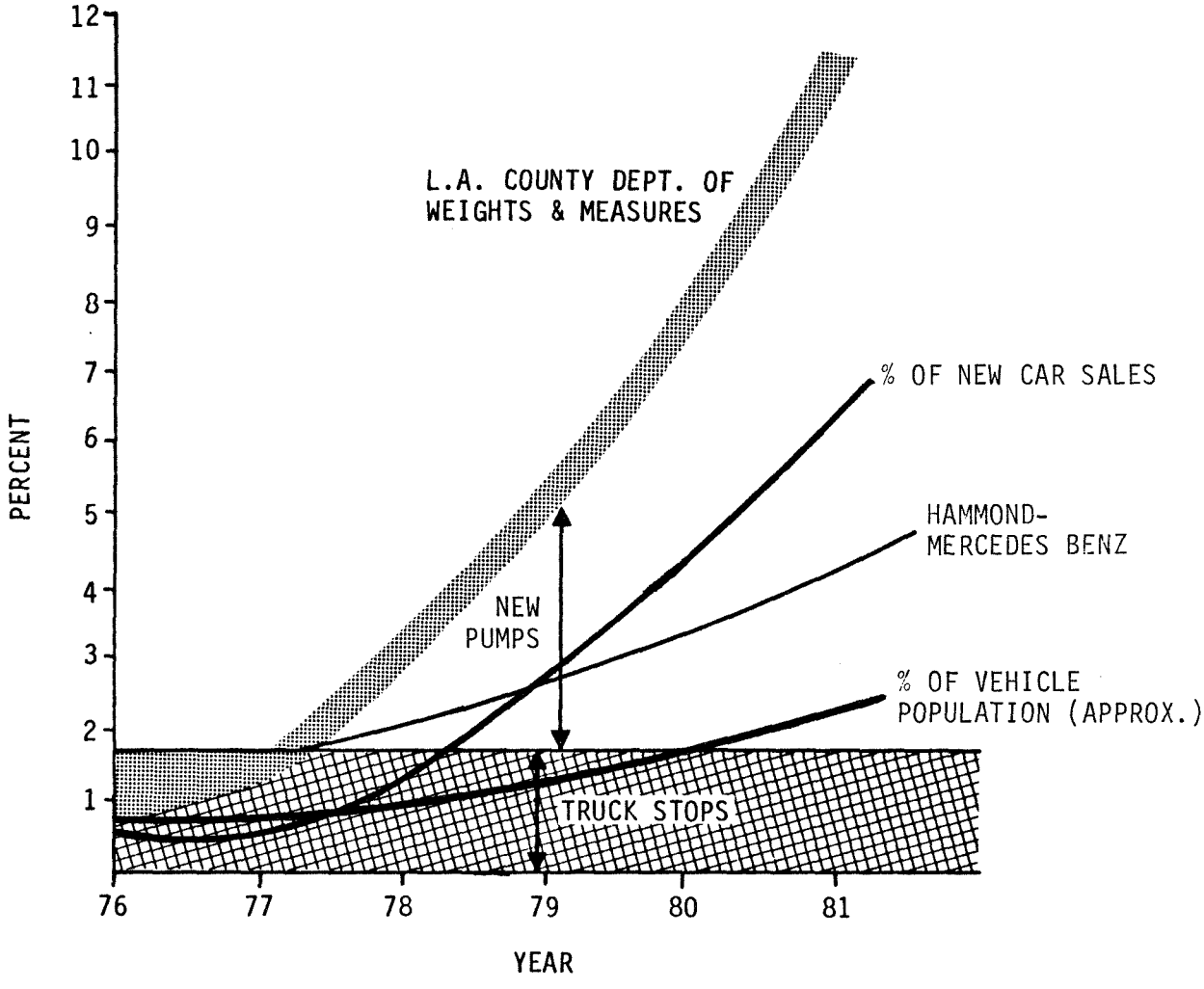


Figure 5-10. GROWTH OF DIESEL OUTLETS IN L.A. COUNTY

LA County alone was not readily obtainable. Hence, statewide sales of diesel cars were used as a surrogate. The line labeled "Hammond-Mercedes-Benz" is an estimate of the growth in diesel outlets from the Mercedes Benz diesel directory (Ref. 25.). It is not possible to estimate the absolute number of retail outlets from the directory, but only relative growth year-to-year. There is a significant difference between the apparent growth represented by the Hammond-Mercedes-Benz data and the County Department of Weights and Measures data. It is believed that the County Department of Weights and Measures data is more accurate because they inspected each retail fuel pump in the county.

Prior to the growth beginning in 1977 to 1978, approximately 1 to 1-1/2 percent of the retail outlets in LA County carried diesel fuel. (Note: There is some uncertainty in the earlier data due to change in record-keeping procedures.) This level of fuel availability was sufficient for both Mercedes Benz and Peugeot to sell diesel automobiles. In LA County there are roughly 4,500 retail motor fuel outlets, which implies 45 to 70 methanol stations would provide methanol availability equivalent to historical diesel availability. For the state as a whole, there are roughly 15,000 service stations, which would imply that 150 to 220 service stations statewide would provide sufficient methanol availability. A further implication is that the level of availability could be provided by one major oil company with 2000 to 3000 service stations by converting 7-1/2 percent of its stations. Since fiberglass tanks have a lifetime of approximately 20 years, approximately 5 percent of such tanks would be replaced anyway. Hence, if the required fuel availability density is as low as implied by the diesel data, no early action or inordinate costs would be necessary for adequate retail availability to be provided. Furthermore, replacing 5 percent of the fiberglass gasoline tanks with steel tanks would increase methanol availability faster than the expected growth in methanol vehicles.

I. REFERENCES

1. Eberle, William R., "Coal Transportation by Rail in the Years 1985 and 2000," Proceedings of the 16th Intersociety Energy Conversion Engineering Conference, pp. 1166-1172, August 1981.

2. Riley, R., Coal Transportation Capability of the Existing Rail and Barge Network, 1985 and Beyond, prepared by Manalytics, Inc. for EPRI, EPRI EA-237, Sept. 1976.

3. Atlas of California, Academic Book Center, Portland, Oregon, 1979.

4. Chuang, Kang-Chun, The Pipeline Transmission of Coal and Coal-Derived Fuel Gases, Chemical Engineering Thesis for West Virginia University, 1976.

5. Kulp, G. et al., Transportation Energy Conservation Data Book: Edition 4, Oak Ridge National Laboratory for the U.S. Dept. of Energy, Report No. ORNL-5654, September 1980.

6. A Technology Assessment of Coal Slurry Pipelines, Technology Assessment, Congress of the United States, March 1978.

7. Ruderman, Henry et al., Regional Environment - Energy Data Book, Western Region, Lawrence Berkeley Laboratory for the U.S. Dept. of Energy, Report No. DOE/TIC-10114/2, December 1978.

8. Office of Technology Assessment, The Direct Use of Coal: Prospects and Problems of Production and Combustion, April 1979.

9. TERA, Inc. Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates, prepared for the U.S. Dept. of Energy, Report No. DOE/EIA-0102/47, January 1979.

10. Rubin, B. et al., An Assessment of the Potential for Use of Alaskan Coal in California, Lawrence Livermore Laboratory, Report No. UCRL-52511, June 1978.

11. University of Oklahoma and Radian Corporation, Energy from the West, Volume IV Appendices, Progress Report of technology assessment of western energy resource development, July 1977.

12. Banks, W. F., "Economics of Non-Water Coal Slurry Systems," Proceedings of the 4th International Technical Conference on Slurry Transportation, pp. 165-170, March 1979.

13. Faddick, R. R., "Flow Properties of Energy Slurries, Featuring Coal," Proceedings of the 3rd International Technical Conference on Slurry Transportation, pp. 93-98, March 1978.

14. Shonka, D. B., editor, Transportation Energy Conservation Data Book, Edition 3, Oak Ridge National Laboratory for the U.S. Dept. of Energy, Report No. ORNL-5493, February 1979.

15. Dutkiewicz, B., "Methanol Competitive with LNG on Long Haul," The Oil and Gas Journal, pp. 166-178, April 30, 1973.

16. Socdjanto, P. and Schaffert, F., "Transporting Gas - LNG vs. Methanol," The Oil and Gas Journal, pp. 88-92, June 11, 1973.

17. Paul, J. K., editor, Methanol Technology and Application in Motor Fuels, published by Noyes Data Corporation, 1978.

18. Santhanam, C. J. et al., "Non-Water Slurry Pipelines - Potential Techniques," Proceedings of the 5th International Technical Conference on Slurry Transportation, pp. 93-103, March 1980.

19. Aude, T. C. and Chapman, J. P., "Coal/Methanol Slurry Pipelines," Proceedings of the 5th International Technical Conference on Slurry Transportation, pp. 106-114, March 1980.

20. Winter, C. and Kohll, A., "Energy Imports: LNG vs. MeOH," Chemical Engineering, Vol. 80, pp. 233-238, November 12, 1973.

21. Hagen, D. L., "Methanol as a Fuel: A Review with Bibliography," Alcohols As Motor Fuels, pp. 189-221, published by Society of Automotive Engineers, 1980.

22. Badger Plants, Inc. "Aspects of Commercializing Coal-Derived Methanol Fuels in the United States: 1985 to 2000," Vol. 1 & 2, Market Evaluation, prepared for the U.S. DOE, FE-2416-44 March, 1980.

23. Keller, J. L., G. M. Nakaguchi, and J. C. Ware, Methanol Fuel Modification for Highway Vehicle Use," Union Oil Company of California for U. S. Department of Energy, Contract No. EY-76-C-04-3683 (July 1978).

24. Teel, H. L., "Multi-Products Pipelining of Ethanol/Hydrocarbon Blends" and "Transportation of Fuel Grade Ethanol by a Multi-Products Pipeline," papers presented at Alcohol as an Octane Enhancer in the 80's conference, San Antonio, TX, March 24-25, 1982.

25. Mercedes-Benz, Directory of Diesel Fuel Stations and Authorized Mercedes-Benz Dealers, Montvale, New Jersey, 1978 through 1982.

CHAPTER SIX

AIR-QUALITY IMPACT OF METHANOL USE IN VEHICLES

A. INTRODUCTION

The South Coast Air Basin of southern California has one of the most persistently severe photochemical air pollution problems in the world. The problem is both pervasive and difficult to control. There is a great need for control measures that can reduce the amount of reactive emissions released into the atmosphere. One potential long-term control strategy is the use of methanol as an alternative fuel. In this chapter we describe the likely air quality impacts resulting from the large-scale use of methanol as an automotive fuel in southern California.

The other purpose of the work described in this chapter was to perform a screening analysis and consider whether the use of methanol could cause new problems of air pollution. For example, there was some concern that the ambient concentration of formaldehyde could increase dramatically over current levels. The analysis described in this chapter indicates that the formaldehyde concentration would not increase significantly.

There are several reasons for selecting the South Coast Air Basin. Almost 10 million people, half the population of California, live within the counties of Los Angeles, Orange, Riverside, and San Bernardino that make up the Basin. In addition, the availability of extensive compilations of emissions and meteorological information enables the application of rigorous analytical procedures. For example, past and future estimates of pollutant emissions are summarized in the Air Quality Management Plan (AQMP) issued by the South Coast Air Quality Management District (SCAQMD). While our attention in this chapter is focused on applications within the Basin, the procedures introduced can easily be applied elsewhere.

The chapter is structured in the following manner. We begin with a brief discussion of the atmospheric chemistry of methanol and formaldehyde. The next section includes a discussion of a mathematical model that describes the formation and transport of photochemical air pollution. When combined with emissions and meteorological data, this model is used to predict the likely ambient air quality impacts of different levels of methanol usage in the year 2000. Those calculations enabled us to estimate concentrations of such air pollutants as ozone, formaldehyde, peroxyacetyl nitrates, and oxides of nitrogen. The environmental impacts of these and other pollutants, are briefly summarized in the final section.

B. ATMOSPHERIC REACTIONS OF HYDROCARBONS

1. Introduction

Photochemical smog is a product of the reactions that occur between oxides of nitrogen (NO_x) and reactive organic compounds (ROC) in the atmosphere, in the presence of sunlight. The ROC are commonly referred to as

hydrocarbons, even though many ROC species contain atoms other than carbon and hydrogen. Reactive organic compounds enter the atmosphere via unburned or incompletely combusted gasoline from automobile exhaust, vapor losses in the filling of gasoline storage tanks, organic products from chemical manufacturing plants, and organic solvents from processes such as dry cleaning. Most of the nitrogen oxides come from combustion processes.

A description of the overall chemistry of the atmosphere is given in Ref. 25. Here we give only a short, and necessarily simplified, account of that chemistry. Our primary concern is with the atmospheric chemistry of methanol and that of its by-product, formaldehyde. Both of these compounds, if emitted into the atmosphere, could contribute to the formation of photochemical oxidants. There are several potential sources of these species. For example, the exhaust emissions from methanol-fueled vehicles would contain both methanol and formaldehyde. Another source of methanol and its additives would be from fuel evaporation during storage, marketing and transfer.

The most important reactions between ozone and oxides of nitrogen are the following:

$$NO_2 + \text{light} \longrightarrow NO + O \tag{1}$$

$$O + O_2 + M \longrightarrow O_3 + M \tag{2}$$

$$NO + O_3 \longrightarrow NO_2 + O_2 \tag{3}$$

In the presence of hydrocarbons, here represented as RH, OH can cause the following reactions:

$$RH + OH \longrightarrow R^{\bullet} + H_2O \tag{4}$$

$$R^{\bullet} + O_2 \longrightarrow RO_2^{\bullet} \tag{5}$$

$$RO_2^{\bullet} + NO \longrightarrow NO_2 + RO^{\bullet} \tag{6}$$

Reaction (6) shifts the equilibrium between reactions (1), (2), and (3). RO_2 consumes NO in the atmosphere and thus less NO remains to react with O_3. As a result, O_3 accumulates in the atmosphere. This fact explains why the severity of photochemical smog is traditionally measured by the ozone concentration in the atmosphere. In Los Angeles, the current smog alert levels (hourly averages), using ozone as an indicator for photochemical activity are as follows:

first stage alert	0.20 part per million (ppm) ozone,
second stage alert	0.35 ppm ozone,
third stage alert	0.50 ppm ozone.

2. Atmospheric Reactions of Formaldehyde

The incomplete combustion of methanol produces formaldehyde as the main intermediate product:

$$CH_3OH + \frac{1}{2}\,O_2 \longrightarrow HCHO + H_2O \qquad (7)$$

where CH_3OH is methanol and HCHO is formaldehyde. Gaseous formaldehyde undergoes two primary reactions in the atmosphere:

(i) Photolysis. $HCHO + \text{light} \longrightarrow HCO^{\bullet} + H^{\bullet}$

$$HCO^{\bullet} + O_2 \longrightarrow HO_2^{\bullet} + CO$$

$$H^{\bullet} + O_2 \longrightarrow HO_2^{\bullet}$$

(ii) Reaction with OH.

$$HCHO + OH^{\bullet} \longrightarrow HO_2^{\bullet} + CO + H_2O$$

The HO_2 radical is important because of its ability to convert NO to NO_2:

$$NO + HO_2^{\bullet} \longrightarrow NO_2 + OH^{\bullet}$$

Formaldehyde, acetaldehyde (CH_3CHO), and higher aldehydes also occur from photochemical oxidation of hydrocarbons. The atmospheric chemistry of acetaldehyde is very similar to that of formaldehyde and involves photolysis and reactions with OH.

The rates of reaction of various hydrocarbon compounds with the hydroxyl radical are shown in Table 6-1. In that table, we can see that aldehydes react roughly as rapidly as olefins. Aldehydes, however, also undergo rapid photolysis to yield reactive radicals and other fragments.

A modeling study of the influence of aldehydes on the formation of smog was carried out by Dodge and Whitten (Ref. 1). They used over fifty steps to model the reactions and estimated photodissociation rate constants. They found that the addition of 0.5 ppm of aldehydes to a hydrocarbon/NO_x system greatly increased the formation of ozone. The effect was more pronounced for the less reactive n-butane/NO_x system than for the propylene/NO_x system. Even in the latter, more reactive system, the increased reactivity was readily observable. Thus, because aldehydes can generate free radicals in photolytic reactions, they can markedly accelerate the formation of smog. In passing it should be noted that the typical levels of formaldehyde observed in the atmosphere are considerably lower than the 0.5 ppm concentration used in the above smog chamber experiments.

3. Atmospheric Reactions of Methanol

The reactivity of methanol is quite low. For example, the rate constant for the reaction of methanol with OH is less than one-half the rate constant for the reaction of butane with OH (see Table 6-1). Nevertheless, methanol could contribute to smog formation at sufficiently high concentrations. We would like to know then if unburned methanol from methanol-fueled automobiles could increase the production of photochemical oxidants. The

Table 6-1. PHOTOCHEMICAL REACTIVITY OF ORGANIC COMPOUNDS: RATE CONSTANTS FOR REACTION WITH HYDROXYL RADICAL

COMPOUND	k x 10^{-4} ($ppm^{-1}min^{-1}$)
Ethylene	0.45
1,2,4 Trimethyl Benzene	4.9
m-Xylene	3.4
Toluene	1.7
Benzene	0.56
Trans-2-Butene	10.5
Propene	2.1
Propionaldehyde	2.2
Acetaldehyde	2.2
Formaldehyde	2.1
n-Butane	0.35
Propane	0.25
Ethane	0.045
Acetylene	0.022
Carbon Monoxide	0.021
Methanol	0.148
Methane	0.0012

k is the rate constant (ppm^{-1} min^{-1}) for the reaction between the compound and the hydroxyl (OH) radical.

SOURCE: (Ref. 26).

air quality model (Ref. 2) was modified to account for methanol's reactions with OH and O_2. This section briefly discusses the chemistry of methanol on which the modifications were based.

The major photochemical reaction of methanol involves abstraction of a hydrogen atom by a hydroxyl radical (Ref. 3):

$$CH_3OH + \dot{O}H \longrightarrow \dot{C}H_2OH + H_2O \qquad (8)$$

CH_2OH is called the hydroxy-methyl radical. According to Atkinson et al. (Ref. 4), such an α-alkoxy radical, ROH, can undergo four main reactions: reaction with O_2, reaction with NO and NO_2, decomposition, and isomerization. The latter two are applicable only to larger α-alkoxy radicals and

not to the hydroxy-methyl radical. The more important of the first two reactions, according to Ref. 5, is the reaction with O_2 to form formaldehyde:

$$CH_2OH + O_2 \longrightarrow HCHO + HO_2^{\bullet} \quad (9)$$

The reactions involving NO_x are:

$$CH_2OH + NO \longrightarrow CH_3ONO \quad (10)$$

$$CH_2OH + NO_2 \longrightarrow CH_3ONO_2 \quad (11)$$

These two reactions, however, are insignificant compared to reaction (9). For example, Carter et al. (Ref. 3) reported smog chamber data for typical photochemical reactions of ethanol. They reported that the product yield of formaldehyde was as much as 100 times more than methyl nitrate (CH_3ONO_2). Further, Ito et al. (Ref. 6) found that CH_3ONO_2 would not be stable under solar radition. The lifetime of CH_3ONO_2 was estimated by Taylor, et al. (Ref. 7) to be approximately 2 minutes. In considering the relative importance of reactions (8) and (9) compared to (10) and (11), we should compare both the rate constants and the likely ambient concentrations of the reacting species. The reaction constant for reaction (8) is about 1.00×10^{-12} cm^3/molecule-sec (Ref. 8) and that for reaction (9) is 6.38×10^{-16} cm^3/molecule-sec. The ambient concentration of O_2 in the atmosphere is approximately 10^{18} molecules/cm^3 and that of OH is about 10^7 molecules/cm^3. For reactions (10) and (11), no rate constants were available. The concentration of NO in the atmosphere, however, is about 10^{12} molecules/cm^3. Thus, reactions (10) and (11) would not be significant in comparison with (9), unless their rate constants were about 10^6 times higher than the rate constant for reaction (9), which is unlikely.

Equations (8) and (9) were thus chosen to be included to account for the dominant features of methanol chemistry.

The point should be made that olefins and aromatics as well as methanol form formaldehyde and reactive radicals. For example, ethylene reacts as follows (Ref. 10):

$$CH_2{=}CH_2 + OH^{\bullet} + O_2 \longrightarrow \dot{C}H_2O_2CH_2OH$$

$$\dot{C}H_2O_2CH_2OH + NO \longrightarrow \dot{C}H_2OCH_2OH + NO_2$$

$$\dot{C}H_2OCH_2OH \longrightarrow HCHO + \dot{C}H_2OH$$

The rate constants for these reactions are significantly larger than the rate constant for a sequence with methanol. The photochemical reactivity of methanol is comparable to the reactivities of low-molecular-weight alkanes, which are among the less reactive hydrocarbons.

Therefore, the atmospheric impact of methanol, though not negligible, is likely to be less serious than that of ethylene, higher alkanes, or aromatics.

The photochemical reactivity of organic compounds may often be assessed from the results of smog-chamber experiments. Experimental studies of the atmospheric chemistry of methanol and formaldehyde were reported by Bechtold and Pullman (Ref. 22), who compared mixtures of reactive organic gases whose compositions were representative of exhaust from a methanol-fueled vehicle and exhaust from a gasoline-fueled vehicle. The simulated exhaust from the gasoline-fueled vehicle was diluted by a factor of about three in order to obtain the same concentration of NO_x as for the methanol-derived exhaust. In one set of comparable data, when the concentration of NO_x was 0.40 ppm, and the ratio between the mass concentrations of organic species in the methanol-derived exhaust to that in the gasoline-derived exhaust was 3.8, the maximum concentrations of ozone in the methanol case and the gasoline case were 1.50 and 1.04 respectively. Clearly, methanol exhaust would produce a much lower concentration of ozone than gasoline exhaust of equal concentration. Obviously, this is only an order-of-magnitude estimate. Another interesting result from the smog-chamber experiments was that the diluted, gasoline-derived exhaust produced a higher concentration of formaldehyde than did the undiluted exhaust from the methanol-fueled vehicle. More smog-chamber experiments need to be conducted in order to confirm the results of Bechtold and Pullman.

C. AIR-QUALITY MODELING CALCULATIONS FOR SOUTH COAST AIR BASIN

1. Description of Air Quality Model

Over the last twenty years, research workers have made efforts to understand the chemical and physical processes which lead to the formation of photochemical smog. Some of the information obtained from that work has been applied to the development of models which simulate air quality in the basin. One such model was developed at Caltech by McRae and Seinfeld (Ref 2, 11, 17). The air-quality model calculates the amounts of secondary atmospheric pollutants such as ozone and peroxyacyl nitrates (PAN), given the emissions of reactive organic compounds (ROC) and oxides of nitrogen (NO_x) that enter the atmosphere from various sources such as automobiles, stationary power plants, solvents, petroleum production, marketing, and refining operations. Ozone is widely accepted as a good index of all the complex reactions which take place among reactive organic compounds and oxides of nitrogen in the polluted atmosphere. The reactive organic compounds are divided into six classes according to reactivity. For our analysis, the model was also modified in order to treat methanol as a specific pollutant. The methanol chemistry was included in the model for completeness even though the results of subsequent modeling calculations did indicate that methanol contributed relatively little to the formation of ozone. The model is described in detail by McRae et al. (Ref. 11), and the essence of their formulation is summarized below.

Modeling of urban air pollution involves a description of the formation and transport of chemically reactive species in the atmosphere. Most models make use of the ensemble-averaged atmospheric diffusion equation (Ref. 12). The area covered by a model is called an airshed, which in our case is the South Coast Air Basin (see Figure 6-1). This airshed must be divided into grid cells where each cell has horizontal and vertical dimensions on the order of several kilometers and tens of meters, respectively. The diffusion equation is averaged over grid cells and the input parameters, such as wind velocities and eddy diffusivities. The equation is also averaged over a certain time interval which equals the time step for the numerical solution. Then it is assumed that the volume-average reaction rate is the same as the reaction rate based on the volume-average cell concentrations. The form of the diffusion equation which is the basis for most airshed models is:

$$\frac{\partial c_i}{\partial t} + \nabla \cdot (\underline{u} c_i) = \nabla \cdot (K \nabla c_i) + R_i(c_1, \ldots, c_p); \; i = 1,2, \ldots p$$

where c_i is the concentration of species i, $\underline{u}$ is the mass average velocity, K is the eddy diffusivity, and R_i is the rate of reaction of species i.

The vertical extent, or the depth of the airshed, is a parameter that has a major influence on the choice of the boundary conditions and the implementation of the computational procedures. In most earlier studies the vertical extent was chosen to be the base of an elevated inversion layer. This selection could cause difficulties in establishing the appropriate upper-level boundary conditions at night when the airshed is not ventilated and any ozone trapped aloft could not be fumigated to the ground the next day. To alleviate this problem, computational cells above the mixed layer are included so that atmospheric conditions are simulated throughout the night. In this way

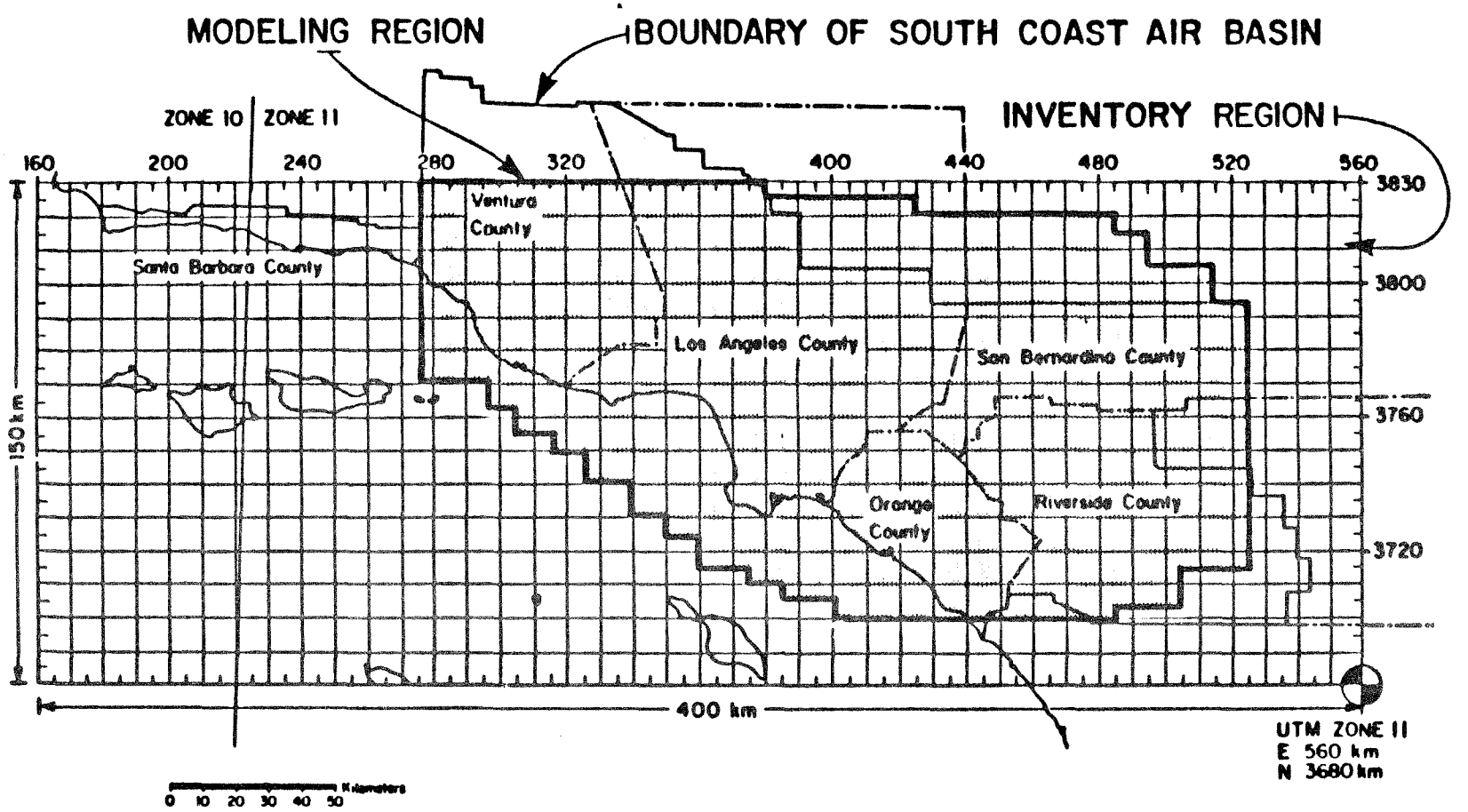


Figure 6-1. DEFINITION OF COMPUTATIONAL GRID SYSTEM FOR THE SOUTH COAST AIR BASIN (Ref. 2)

entrainment and boundary-layer growth can be modeled by variations in the vertical profile for the eddy diffusivity.

The initial and boundary conditions must be specified to complete the mathematical formulation of the model. The boundary conditions are statements of mass continuity across the bounding surfaces of the airshed and are described by Reynolds *et al.* (Ref. 13).

Under certain circumstances, less complex forms of the governing equation are desirable. In particular, the air-quality impact may only be needed for a specific location. A trajectory model, which follows a parcel of air traversing the airshed, is often used in these circumstances. The most common representation of a trajectory model, as shown by Eschenroeder and Martinez, and by Lloyd, et al. (Refs. 14, 15), can be expressed in the form

$$\frac{\partial c}{\partial z} = \frac{\partial}{\partial z}\left(K_{zz}\frac{\partial c}{\partial z}\right) + R(c),$$

where K_{zz} is the vertical eddy diffusivity. A Lagrangian analysis is then used where the coordinate system is adjusted for the horizontal wind field. A change of variables, from the fixed system to the moving coordinate system, is employed. This computational method is in general faster than the fixed or Eulerian grid approach.

Certain assumptions are useful in simplifying the Lagrangian form of the diffusion equation. The vertical bulk transport is assumed to be small in comparison to the turbulent diffusion, the loss or gain of material from horizontal diffusion is considered to be negligible, and the wind-shear effects are neglected.

We can therefore see that the model used in this study is a comprehensive mathematical system for describing urban air pollution. In order for the model to give the concentrations of chemically reactive species, three major input components are required: (1) a meteorological description, such as wind speed and trajectories and vertical temperature variation; (2) a source description of the temporal and spatial distribution of emissions for all significant pollutant sources; and (3) a kinetic mechanism describing rates of atmospheric chemical reactions as a function of concentrations of various species present.

The meteorological description must account for the interactions among the various components. For example, temperature variations affect the inversion height which in turn influences the transport of chemical species in the atmosphere. The emissions data must be accurate and detailed and specify emissions from diverse sources. They must also be well structured so that emissions from one source can be varied without altering the remainder of the emissions.

A complicated problem involves simulation of the chemical reactions of the atmosphere. The chemical interactions can be described by the 52-step reaction mechanism, proposed by Falls and Seinfeld (Ref. 16), McRae et al. (Ref. 11), and McRae and Seinfeld (Ref. 17), and shown in Table 6-2. This

Table 6-2. CHEMICAL MECHANISM USED IN AIR-QUALITY MODEL

Photolysis of NO_2 and basic $NO-NO_2-O_3$ photolytic cycle

$$NO_2 + h\nu \xrightarrow{1} NO + O(^3P)$$

$$O(^3P) + O_2 + (M) \xrightarrow{2} O_3 + (M)$$

$$O_3 + NO \xrightarrow{3} NO_2 + O_2$$

$$NO_2 + O(^3P) \xrightarrow{4} NO + O_2$$

$$NO + O(^3P) \xrightarrow{5} NO_2$$

Chemistry of NO_3 (nitrogen trioxide)

$$NO_2 + O(^3P) \xrightarrow{6} NO_3$$

$$O_3 + NO_2 \xrightarrow{7} NO_3 + O_2$$

$$NO_3 + NO \xrightarrow{8} 2NO_2$$

Nitrous acid and peroxy nitrous acid chemistry

$$NO + OH \xrightarrow{9} HONO$$

Photolysis of HONO

$$HONO + h\nu \xrightarrow{10} OH + NO$$

Nitrous acid chemistry

$$HO_2 + NO_2 \xrightarrow{11} HONO + O_2$$

$$HONO + OH \xrightarrow{12} NO_2 + H_2O$$

$$NO_2 + HO_2 \xrightarrow{13} HO_2NO_2$$

$$HO_2NO_2 \xrightarrow{14} HO_2 + NO_2$$

Table 6-2. CHEMICAL MECHANISM USED IN AIR-QUALITY MODEL (Continued)

Conversion of NO to NO_2

$$HO_2 + NO \xrightarrow{15} NO_2 + OH$$

$$RO_2 + NO_2 \xrightarrow{16} NO_2 + RO$$

$$RCO_3 + NO \xrightarrow{17} NO_2 + RO_2 + CO_2$$

Nitric acid ($HONO_2$) formation

$$NO_2 + OH \xrightarrow{18} HONO_2$$

Hydroperoxyl radical formation

$$CO + OH \xrightarrow{19} HO_2 + CO_2$$

Photolysis of ozone

$$O_3 + hv \xrightarrow{20} O(^3P) + O_2$$

Photolysis of formaldehyde

$$HCHO + hv \xrightarrow{21} 2HO_2 + CO$$

$$HCHO + hv \xrightarrow{22} H_2 + CO$$

Formaldehyde chemistry

$$HCHO + OH \xrightarrow{23} HO_2 + H_2O + CO$$

Photolysis of higher aldehydes

$$RCHO + hv \xrightarrow{24} RO_2 + HO_2 + CO$$

Higher aldehyde chemistry

$$RCHO + OH \xrightarrow{25} RCO_3$$

Olefin chemistry (OLE)

$$C_2H_4 + OH \xrightarrow{26} RO_2$$

$$C_2H_4 + O \xrightarrow{27} RO_2 + HO_2$$

$$OLE + OH \xrightarrow{28} RO_2$$

Table 6-2. CHEMICAL MECHANISM USED IN AIR-QUALITY MODEL (Continued)

$$OLE + O \xrightarrow{29} RO_2 + RCO_3$$

$$OLE + O_3 \xrightarrow{30} (a_1)\ RCHO + (a_2)\ HCHO + (a_3)\ HO_2 + (a_4)\ RO_2 + (a_5)\ OH + (a_6)\ RO$$

Alkane chemistry (ALK)

$$ALK + OH \xrightarrow{31} RO_2$$

$$ALK + O \xrightarrow{32} RO_2 + OH$$

Aromatic chemistry (ARO)

$$ARO + OH \xrightarrow{33} RO_2 + RCHO$$

Alkoxyl radical chemistry

$$RO \xrightarrow{34} (b_1)\ HO_2 + (1-b_1)\ RO_2 + (b_2)\ HCHO + (b_3)\ RCHO$$

Photolysis and chemistry of RONO

$$RONO + h\nu \xrightarrow{35} NO + RO$$

$$RO + NO \xrightarrow{36} RONO$$

$$RO + NO_2 \xrightarrow{37} RONO_2$$

$$RO + NO_2 \xrightarrow{38} RCHO + HONO$$

Peroxy nitrate chemistry

$$NO_2 + RO_2 \xrightarrow{39} RO_2NO_2$$

$$NO_2 + RO_2 \xrightarrow{40} RCHO + HONO_2$$

$$RO_2NO_2 \xrightarrow{41} NO_2 + RO_2$$

Peroxyacyl nitrate (PAN) chemistry

$$RCO_3 + NO_2 \xrightarrow{42} PAN$$

$$PAN \xrightarrow{43} RCO_3 + NO_2$$

Table 6-2. CHEMICAL MECHANISM USED IN AIR-QUALITY MODEL (Continued)

Dinitrogen pentoxide (N_2O_5) chemistry

$$NO_2 + NO_3 \xrightarrow{44} N_2O_5$$

$$N_2O_5 \xrightarrow{45} NO_2 + NO_3$$

$$H_2O + N_2O_5 \xrightarrow{46} 2\ HONO_2$$

Ozone removal steps

$$O_3 + OH \xrightarrow{47} HO_2 + O_2$$

$$O_3 + HO_2 \xrightarrow{48} OH + 2O_2$$

Ozone wall loss term for smog chamber experiments

$$O_3 \xrightarrow{49} \text{wall loss}$$

Hydrogen peroxide production and photolysis

$$HO_2 + HO_2 \xrightarrow{50} H_2O_2 + O_2$$

$$H_2O_2 + h\nu \xrightarrow{51} 2OH$$

Recombination Reaction for peroxalkyl radicals

$$RO_2 + RO_2 \xrightarrow{52} 2RO$$

Methanol chemistry

$$CH_3OH + OH \xrightarrow{53} \dot{C}H_2OH + H_2O$$

$$CH_2OH + O_2 \xrightarrow{54} HCHO + HO_2$$

Equations 1 through 52 were taken from Reference 11.

so-called lumped mechanism groups organic species according to their structures and reactivities.

In the lumped mechanism, distinct organic entities must be abandoned in favor of lumped species. Organic species are divided into seven classes: ethylene, higher olefins, formaldehyde, higher aldehydes, aromatics, alkanes, and methanol. Ethylene is distinguished from higher olefins because of its

relatively low reactivity with OH and its significant ambient concentration. Formaldehyde is separated from higher aldehydes because it photolyses to HO_2, which is substantially different from the RO_2 formed in the photolysis of higher aldehydes. Further, formaldehyde does not lead to PAN formation. We might emphasize that our model is the first of its kind to account for methanol as a separate entity.

Table 6-2 shows that the mechanism used in the model takes into account numerous chemically reactive species whose reactions are closely interrelated. For instance, n-butane, a constituent in gasoline, can react with OH and O to form peroxyalkl (RO_2) radicals and aldehydes. The presence of the RO_2 radical upsets the equilibria among OH and other alkanes, olefins, etc. RO_2 also reacts with NO_x to form more radicals. The 52 reactions therefore had to be carefully selected to be representative of atmospheric reactions. Further information on the mechanism appears in Falls and Seinfeld (Ref. 16).

Detailed discussions of other aspects of the model such as rate constants for photolysis, turbulent-diffusion coefficients, data for surface removal processes, treatment of point-source emissions, and numerical solution of the atmospheric diffusion equation, are again described in the paper by McRae, et al. (Ref. 11).

2. Validation of the Air-Quality Model

The evaluation of model performance is explained in detail by McRae and Seinfeld (Ref. 17). A summary is given here.

Three steps are needed to evaluate the performance of a model. They are (1) a basic assessment of model validity, (2) analysis of the sensitivities of the predictions to uncertainties in model components, and (3) comparison of predictions and observations for past events.

The validity of a model is measured by its correctness relative to basic physics and chemistry as well as to the accuracy of numerical results, e.g., adherence to necessary conditions such as conservation of mass. In this respect, our model uses the latest relevant data and accepted theory. In simulation of urban air pollution, each individual component of the model has been tested to ensure that the model is valid and practical.

Sensitivity analyses of various atmospheric models have been made (Refs. 18, 19, 20, 21) to show how much of the overall uncertainty of a model's output is associated with the individual uncertainty in each input. These analyses show the variables to which the models are most sensitive, and will not be discussed. Note should be made, however, that the analyses allow understanding of the causes of discrepancies between predictions and observation. The model was tested in its trajectory formulation.

In the testing of the present model, predictions were compared with observations for the region known as the South Coast Air Basin and shown in Figure 6-1. This basin provides an ideal site for evaluation of the performance of an urban model because it not only has the most persistently severe photochemical air pollution in the United States, but also displays much variability in meteorology and in densities of emission. The time period

chosen to check the model was the week of 23-28 June, 1974, when a severe air-pollution episode was encountered. The high ozone levels provided a good test of the model's ability to simulate such episodes. Moreover, detailed emissions inventories are available for that year. Available emissions for 130 different source categories were spatially distributed over the region shown in Figure 6-1 (see p. 6-8). Further details of the emission inventory appear in McRae, et al. (Ref. 2). That inventory is different, both in the amounts of emissions and in their composition, from the year 2000 inventory described later in this chapter.

The model was applied to simulate the 2-day period of June 26-27, 1974, and also June 28, 1974, in the Basin. Out of 15 species of pollutants, NO_2 and O_3 provide the most rigid test of a model to simulate photochemical air pollution. Solid lines in Figure 6-2 show predicted conditions, and the dots are the observed concentrations of NO_2 and O_3 in the period cited. The predictions are consistent with the observations. Early-morning peaks are due to emissions from heavy traffic. Peak concentrations for NO_2 are delayed a few hours, and that result is consistent with the time required to oxidize NO. More importantly, the model satisfactorily describes the observed trends of concentration on the second day. This fact is especially encouraging for control purposes. By running the model for a period longer than the characteristic ventilation of the airshed, minimization of the influence of uncertainties in specification of the intial conditions is possible.

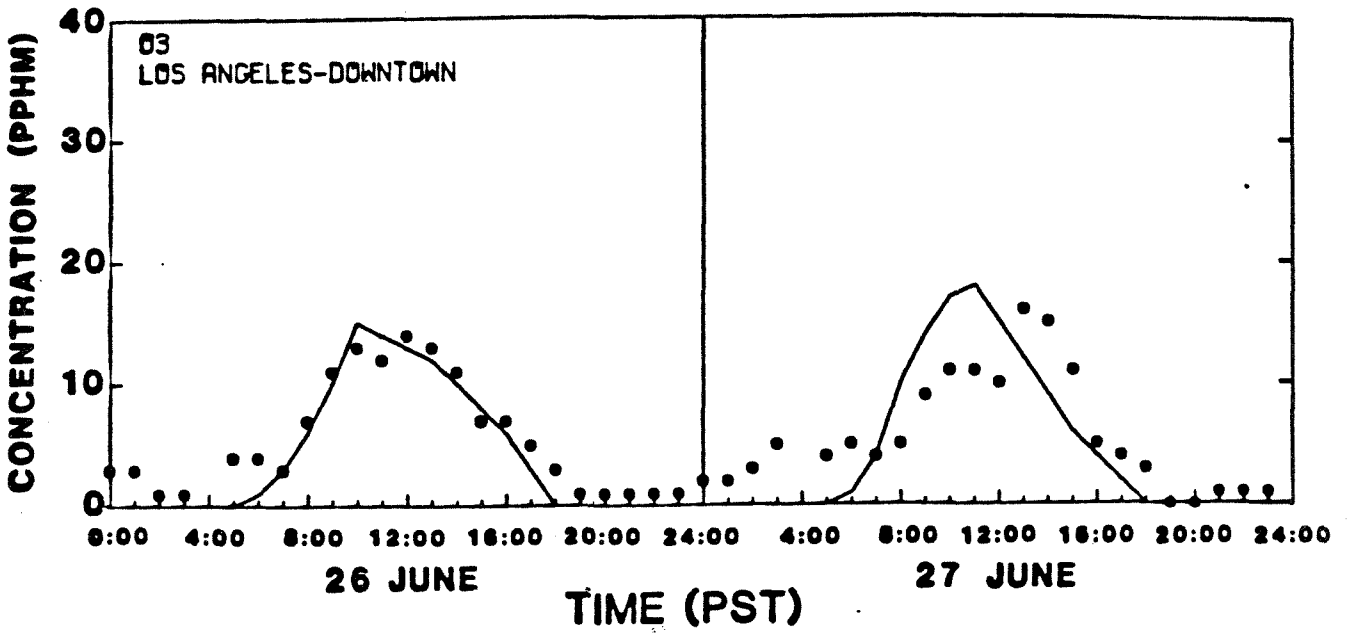
In summary, we have shown that the essential trends of the prediction and observations are in good agreement. Further, our model utilizes the latest relevant data and state-of-the-art knowledge of air pollution. We therefore conclude that the model provides a valid representation of atmospheric dynamics.

As described above, the air-quality model was validated before it was modified to include the chemistry of methanol. After modifying the model for methanol, we would have wished to repeat the validation runs with the modified model. We could not validate the modified model using historical data for the obvious reason that methanol has never been a major part of the atmosphere in Los Angeles. In addition, no suitable smog-chamber data were available for comparison with the predictions of the modified model. In the only published smog-chamber experiments with gas mixtures containing methanol (Ref. 22), not enough information was provided to enable us to simulate the experiments using the modified McRae-Seinfeld model. Nevertheless, we feel confident that equations 53 and 54 correctly represent the chemistry of methanol and that the modified model is correct.

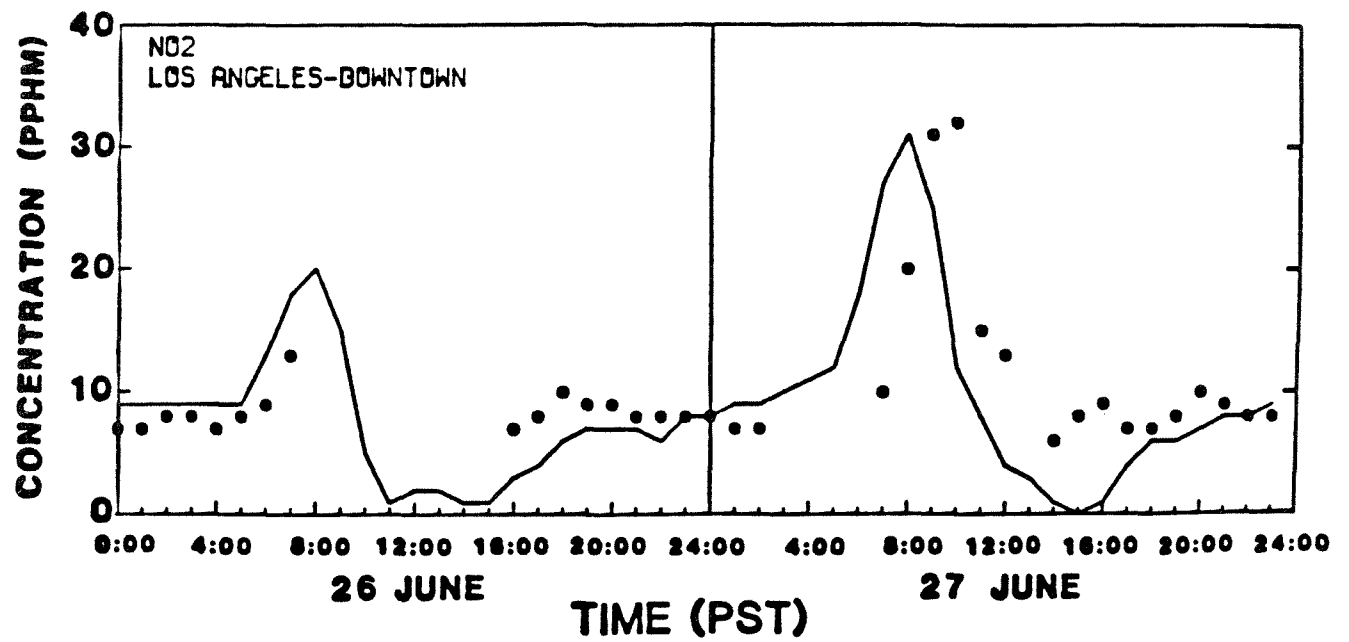
3. Emission Inventory Data for the Air-Quality Model

a. Summary. Calculations were based on projected emissions for the year 2000. At that future date the potential benefits of existing emissions regulations would have been realized. The year 2000 is a feasible date by which methanol could be expected to become an important fuel in California. Inputs to the air-quality model were prepared for a base case and for a range of values for the percent of substitution of methanol for gasoline. We did not explicitly consider the possible effect on photochemical smog of the use of methanol in stationary Sources. We assumed only that

Figure 6-2. PREDICTED VS. OBSERVED O_3 AND NO_2 CONCENTRATIONS FOR THE PERIOD OF JUNE 26-27, 1974



(a)



(b)

current regulations would remain in force and that operators of industrial boilers and electric utility companies would limit emissions of oxides of nitrogen by the most economical means, which could include the use of methanol. Other pollutants like sulfur oxides and particulates would also be reduced if methanol were substituted for fuel oil or coal. These pollutants are mentioned elsewhere in this report.

b. Base-Case Inventories. Two base-case inventories for the year 2000 were considered. The first set of figures was taken directly from the projections made by the South Coast Air Quality Management District (SCAQMD) and published in the Air Quality Management Plan, 1982 Revision (AQMP). The second base-case inventory was obtained using our own (CMAP) calculations of emissions for highway motor vehicles and the SCAQMD projections for all other sources. The purpose of the CMAP inventory was simply to provide a means of checking the SCAQMD figures.

Highway-vehicle emissions for the CMAP base case were estimated by the procedure described below. The method of calculation was originally developed by the California Air Resources Board (CARB). In order to simplify the calculation, we assumed that vehicle emission standards for future years would remain at their 1981 levels. We calculated emission factors for a fleet of vehicles having the emission characteristics of 1981 model-year vehicles. We used the year 2000 vehicle population as projected by the Southern California Association of Governments. The SCAQMD's projections of emissions from motor vehicles in 2000, which were published in the AQMP, were about 20 percent lower than our (CMAP) estimates, which are based on the assumption that emission standards would not be relaxed or tightened between now and the year 2000. Clearly the difference was at least partly due to the fact that the SCAQMD projections include the impact of motor-vehicle-pollution-control regulations approved for implementation in future years beyond 1981. Some of those regulations have already been shelved and may not now be implemented. Another possible reason for the difference was that the emission factors we used, unlike those used in making the SCAQMD projections, were not adjusted for vehicle speed or for variations in the driving cycles of vehicles.

SCAQMD Inventory. Projections of emissions in the year 2000, taken from the Air Quality Management Plan, 1982 Revision, are shown in Tables 6-3 and 6-4 together with the emission inventories for 1974 and 1979. A comparison of the historical data and the projected data shows that the relative contributions from different sources have been changing. Furthermore, the total tonnage of emissions of pollutants does not appear to decrease dramatically from year to year, despite progressively stricter pollution standards. There are three probable reasons for this trend:

(1) The most important reason is that emissions increase because of economic growth. Additional pollution is generated, for example, by the increased vehicle traffic, the higher rate of electric power generation, and higher levels of production from industry.

(2) Some of the pollution-abatement regulations apply only to new automobiles and new equipment. The results of such regulations will not be observable until most of the older stock of polluting equipment has been retired from service.

(3) The inventories of pollutants for the later years are more accurate and include sources of pollution which had been underestimated or not included in the emission inventories of earlier years. Officials of the South Coast Air Quality Management District (SCAQMD) informed us that the quality of the emission-inventory data has improved significantly in recent years.

Table 6-3. INVENTORY OF EMISSIONS OF NITROGEN OXIDES IN THE SOUTH COAST AIR BASIN (Tons/Day)

	HISTORICAL DATA		PROJECTED EMISSIONS	
	1974	1979	1987	2000
STATIONARY SOURCES			1982 AQMP Revision	1982 AQMP Revision
Oil and Gas Production	61	11	7	2
Petroleum Refinery	125	72	71	71
Petroleum Storage, Marketing and Transfer	-	-	-	-
Organic Solvent Usage	2	1	1	1
Metallurgical & Mineral Operations	60	9	8	7
Misc. Industrial Sources	10	1	1	1
Fuel Combustion-Power Plants	194	136	61	48
Industrial, Commercial and other Boilers	96	166	186	206
Agricultural Sources	-	-	-	-
Miscellaneous Sources	-	10	23	27
TOTAL STATIONARY SOURCES	548	406	358	363

Abbreviations: AQMP - Air Quality Management Plan

The figures in Table 6-3 were obtained from the South Coast Air Quality Management District.

Table 6-3. INVENTORY OF EMISSIONS OF NITROGEN OXIDES IN THE SOUTH COAST AIR BASIN (Tons/Day) (Continued)

	HISTORICAL DATA		PROJECTED EMISSIONS	
	1974	1979	1987	2000
MOBILE SOURCES			1982 AQMP Revision	1982 AQMP Revision
On-Road Vehicles				
Light-Duty Passenger Autos		412	235	192
Medium & Light-Duty Trucks		106	72	62
Heavy-Duty Gasoline Trucks		39	33	30
Heavy-Duty Diesel Trucks		165	141	128
Motorcycles		1	2	2
SUBTOTAL, ON-ROAD VEHICLES	776	723	482	413
Other Mobile Sources				
Railroad Trains	31	21	27	30
Marine Craft	13	13	14	16
Aircraft	25	13	15	23
Off-Road Vehicles	8	7	8	10
Mobile Equipment	54	60	56	64
SUBTOTAL, OTHER MOBILE SOURCES	131	114	135	143
TOTAL, MOBILE SOURCES	907	837	602	556
TOTAL EMISSIONS	1455	1243	960	919

Abbreviations: AQMP - Air Quality Management Plan

The figures in Table 6-3 were obtained from the South Coast Air Quality Management District.

Another feature of Table 6-3 and Table 6-4 is that the relative contributions of different sources of emissions in the year 2000 are expected to be different from what they were in 1974. This fact has very important implications for the development of strategies for the control of pollution in future years. For example, power plants contributed 13.3% to total emissions of NO_x in 1974 while industrial, commercial and other boilers contributed 6.6%. In the year 2000 power plants are expected to account for 5.3% of total emissions of NO_x while boilers are expected to be 22.4% of the total. The contribution of on-road motor vehicles to overall emissions of reactive hydrocarbons (RHC), which was 65.0% in 1974 is expected to fall to 33.9% in the year 2000. Over the same period, RHC emissions due to solvent usage are projected to grow from 8.9% of the total in 1974 to 35.2% of the total in the

Table 6-4. INVENTORY OF EMISSIONS OF REACTIVE ORGANIC COMPOUNDS IN THE SOUTH COAST AIR BASIN (Tons/Day)

	HISTORICAL DATA		PROJECTED EMISSIONS	
	1974	1979	1987	2000
STATIONARY SOURCES			1982 AQMP Revision	1982 AQMP Revision
Oil and Gas Production	78	46	38	28
Petroleum Refinery	70	53	47	53
Petroleum Storage, Marketing and Transfer	71	106	73	71
Organic Solvent Usage	121	339	264	309
Metallurgical & Mineral Operations	7	3	3	3
Misc. Industrial Sources	3	20	21	25
Fuel Combustion-Power Plants	6	8	5	5
Industrial, Commercial and other Boilers	4	9	10	11
Agricultural Sources	18	14	15	15
Miscellaneous Sources	9	83	34	41
TOTAL STATIONARY SOURCES	387	681	509	561

Abbreviations: AQMP - Air Quality Management Plan

The figures in Table 6-4 were obtained from the South Coast Air Quality Management District.

Table 6-4. INVENTORY OF EMISSIONS OF REACTIVE ORGANIC COMPOUNDS IN THE SOUTH COAST AIR BASIN (Tons/Day) (Continued)

	HISTORICAL DATA		PROJECTED EMISSIONS	
	1974	1979	1987	2000
MOBILE SOURCES			1982 AQMP Revision	1982 AQMP Revision
On-Road Vehicles				
Light-Duty Passenger Autos		563	282	279
Medium & Light-Duty Trucks		139	76	61
Heavy-Duty Gasoline Trucks		23	13	9
Heavy-Duty Diesel Trucks		14	14	14
Motorcycles		12	7	7
SUBTOTAL, ON-ROAD VEHICLES	884	751	392	370
Other Mobile Sources				
Railroad Trains	8	6	7	8
Marine Craft	1	2	2	2
Aircraft	56	17	21	32
Off-Road Vehicles	19	20	24	28
Mobile Equipment	4	57	69	88
SUBTOTAL, OTHER MOBILE SOURCES	88	102	123	158
TOTAL, MOBILE SOURCES	972	853	515	527
TOTAL EMISSIONS	1359	1534	1024	1088

Abbreviations: AQMP - Air Quality Management Plan

The figures in Table 6-4 were obtained from the South Coast Air Quality Management District.

year 2000. SCAQMD personnel informed us that there has been a trend toward reducing the aromatic content of solvents since 1974. There have also been changes in the reactivity of the hydrocarbons emitted from motor vehicles since the advent of the exhaust catalytic converter.

In developing the emission forecast for the year 2000, the SCAQMD made use of predicted rates of economic and population growth given in the Southern California Association of Government's 1978 projection for different sources of pollutants. These estimates were based on historical inventory data and expected rates of growth of pollution. The forecast, which applies to the South Coast Air Basin, is described more fully in Reference 35. It is a projection of future growth in population, housing, land use, and employment and output in different sectors of the economy. In the 1979 AQMP, the inventory for 1976 was used to predict system-wide emissions for 1982, 1987, and 2000. The AQMP was revised in June of 1982 and the more accurate 1979 inventory was used to predict future emissions. The basis for the projections of future emissions was described in the 1979 AQMP. We used the "baseline" projection, which referred to expected future emissions based on regulations currently in force and those already approved for implementation. In the baseline projection, future emissions were estimated from projected levels of activity of important sources of pollution and corresponding efficiencies for the control of pollution from those sources.

For a given source s and pollutant p, a pollution control factor R_{sp} was defined as:

$$R_{sp} = \frac{100 - C_{sp}}{100 - C_{sp}^{o}} \tag{1}$$

where

C_{sp}^{o} is the pollution-control efficiency in the base year,
C_{sp} is the pollution-control efficiency in the future year, and the subscripts s and p refer to source s and pollutant p, respectively. The superscript 0 refers to the base year data.

The expected level of emission for the future year, E_{sp}, was then given by

$$E_{sp} = R_{sp} \times E^{0}_{sp} \times \left[\frac{A_s}{A_s^{0}}\right] \tag{2}$$

A_s is a measure of the level of activity of the source s, such as the amount of electricity generated or number of vehicle-miles driven, in the future year. A full description of AQMP procedures is given in Reference 33.

CMAP Inventory. The only difference between the CMAP inventory and the SCAQMD inventory was in the projected emissions from highway vehicles in the year 2000. Our calculations were made under the assumption that emission regulations for highway vehicles would not be changed from the

1981 standards. Reference 36 describes the procedures used to estimate future emissions from six classes of highway motor vehicles.

- Light-Duty Passenger Vehicles (LDP)
- Light-Duty Trucks (LDT)
- Medium-Duty Trucks (MDT)
- Heavy-Duty Gasoline Trucks (HDGT)
- Heavy-Duty Diesel Trucks (HDDT)
- Motorcycles (MCY)

Using those procedures developed by the CARB, we were able to calculate population-averaged "composite" emissions for each vehicle class. We used the year-2000 vehicle population as projected by the Southern California Association of Governments to estimate the projected mass emissions in ton/day.

Composite emissions for each class of highway vehicle were calculated using three important sets of data, all of which were obtained from Ref. 36. These were:

(1) Exhaust emission factors:

These factors are defined in accord with a linear plot of exhaust emissions, measured according to the CVS-75 Federal Test Procedure (Ref. 36), versus the odometer reading for the test vehicle. The slope of the graph is referred to as the "deterioration rate," and the intercept on the ordinate axis is called the "emission factor." Figures for 1981-model-year vehicles are given in Table 6-5. These figures are based on vehicle certification emissions data modified to reflect expected emission rates from actual highway vehicles. The EPA and the CARB have carried out surveillance tests of emissions from vehicles owned by the general public. The procedure used by the CARB to assess emissions from owner-operated road vehicles is described in Reference 34. The results of these tests are used to predict the deterioration rate for a given class and model of vehicle.

(2) Figures showing mean odometer reading as a function of age for different classes of vehicles:

They are given in Table 6-6.

(3) The vehicle-age distribution for each class of vehicles:

The figures shown in Table 6-7 are based on the results of vehicle surveys carried out in the state of California. For a given class, the fraction of vehicles aged n years was designated as f_n, and n ranged from 0 to 25.

Table 6-5. EMISSION FACTORS FOR 1981 MODEL-YEAR VEHICLES (g/mile)

POLLUTANT	VEHICLE TYPE					
	LDP	LDT	MDT	HDGT	HDDT	MCY
Oxides of Nitrogen (NO_x)	0.56	1.01	1.14	5.67	13.74	0.76
Reactive Organic Compounds (ROC)	0.33	0.38	0.40	3.25	3.49	2.7

Figures were obtained from the California Air Resources Board, see Ref. 36. Emission Factors are defined as the intercept on the ordinate scale of a linear plot of emissions (g/mile) as a function of vehicle odometer reading (miles).

Abbreviations:

LDP: Light-Duty Passenger Vehicle
LDT: Light-Duty Truck
MDT: Medium-Duty Truck
HDGT: Heavy-Duty Gasoline Truck
HDDT: Heavy-Duty Diesel Truck
MCY: Motorcycle

From the data in Tables 6-5, 6-6, 6-7, and 6-8, we were able to calculate the exhaust emissions of hydrocarbons (HC) and NO_x as a function of vehicle age for each class of vehicle (see Table 6-9).

Let the exhaust emissions of NO_x and HC from a vehicle aged n years be a_{1n} g/mile and a_{2n} g/mile respectively. Then the composite emissions of NO_x and HC are given by

$$\sum_{N=0}^{n=25} a_{1n} x f_n = a_1$$

and

$$\sum_{n=0}^{n=25} a_{2n} x f_n = a_2$$

The results of the calculations are shown in Table 6-10. The data which were used to estimate highway-vehicle emissions were all subject to some degree of error. Notably, the plot of emissions versus vehicle mileage shows a considerable degree of scatter, and thus the figures of "composite" emissions are subject to errors which are difficult to quantify.

Evaporative emissions for gasoline-fueled vehicles were calculated using data obtained from Reference 36 for diurnal emissions and hot soak emissions, and for the number of trips per day. Evaporative emissions were assumed to remain unchanged over the life of the vehicle.

Table 6-6. DETERIORATION RATES FOR 1981 MODEL-YEAR VEHICLES
(g/mile per 10,000 miles)

POLLUTANT	VEHICLE TYPE					
	LDP	LDT	MDT	HDGT	HDDT	MCY
Oxides of Nitrogen (NO_x)	0.10	0.12	0.12	0.09	0.12	0.00
Reactive Organic Compounds (ROC)	0.20	0.20	0.20	0.14	0.04	1.64

Figures were obtained from the California Air Resources Board, see Ref. 36. "Deterioration Rate" is defined by the CARB as the slope of a linear plot of emissions (g/mile) as a function of vehicle odometer reading (miles). Thus it is a rate of increase of emissions with vehicle miles traveled.

Abbreviations:

LDP: Light-Duty Passenger Vehicle
LDT: Light-Duty Truck
MDT: Medium-Duty Truck
HDGT: Heavy-Duty Gasoline Truck
HDDT: Heavy-Duty Diesel Truck
MCY: Motorcycle

The projected numbers of vehicles in the Basin in the year 2000 were obtained from the Southern California Assoication of Governments. The SCAQMD also based its projected emission inventory for the year 2000 on those figures. The projected population of light-duty cars, light-duty trucks, and medium-duty trucks would include diesel-fueled vehicles as well as gasoline-fueled vehicles. The Southern California Association of Governments did not make an estimate of the percentage of such vehicles that would be diesel-fueled in the year 2000. We estimated that, in the year 2000, 15 percent of all vehicles in the three categories above would be diesel-fueled. Diesel-fueled vehicles were assumed to produce the same mass of exhaust emissions of NO_x and ROC as the corresponding gasoline-fueled vehicles. The composition of exhaust from each vehicle type would be different. The diesel-fueled vehicles produce relatively higher emissions of aldehydes, sulfur oxides, and solid particulates. Unlike gasoline-fueled vehicles, however, diesel-fueled vehicles produce almost no evaporative emissions because the fuel system for diesel-fueled vehicles is closed. The calculation of the mass of evaporative emissions is shown in Table 6-11.

Composition of Reactive Organic Emissions. Emissions of reactive organic compounds from different sources consist of different species, all of which have different photochemical reactivities. The Air Quality trajectory model which we used distinguished among seven classes of organic

Table 6-7. ODOMETER MILEAGE AS A FUNCTION OF VEHICLE AGE

VEHICLE AGE (Years)	VEHICLE TYPES		
	LDP, LDT, and MDT	HDGT and HDDT	MOTORCYCLES
0	3,000	0	0
1	13,000	19,700	2,271
2	27,200	39,400	4,542
3	38,700	57,400	6,813
4	48,500	75,400	9,084
5	56,800	90,500	11,355
6	64,800	106,000	13,626
7	71,200	117,000	15,897
8	76,300	129,000	18,168
9	80,800	139,000	20,439
10	84,500	149,000	22,710
11	87,800	156,000	24,981
12	90,500	163,000	27,252
13	93,000	171,000	29,523
14	95,400	178,000	31,794
15	97,700	185,000	31,794
16	100,000	193,000	31,794
17	100,000	200,000	31,794
18	100,000	208,000	31,794
19	100,000	215,000	31,794
20	100,000	222,000	31,794
21	100,000	222,000	31,794
22	100,000	222,000	31,794
23	100,000	222,000	31,794
24	100,000	222,000	31,794
25	100,000	222,000	31,794

The figures in Table 6-7 were taken from Ref. 36 which was published by the California Air Resources Board. They are only intended to be used to calculate emissions as a function of vehicle age. Some older vehicles are shown as having constant odometer mileage, in order to show that vehicle emissions reach an asymptotic value.

Abbreviations:

LDT: Light-Duty Passenger Vehicles
MDT: Medium Duty Truct
HDDT: Heavy-Duty Truck
LDT: Light-Duty Truck
HDGT: Heavy-Duty Gasoline Truck

Table 6-8. AGE DISTRIBUTION OF VEHICLES

FRACTION OF VEHICLE POPULATION AS FUNCTION OF VEHICLE AGE AT BEGINNING OF CALENDAR YEAR

VEHICLE AGE (years)	LIGHT-DUTY PASSENGER CARS	LIGHT-DUTY TRUCKS	MEDIUM-DUTY TRUCKS	HEAVY-DUTY GASOLINE TRUCKS	HEAVY-DUTY DIESEL TRUCKS	MOTOR-CYCLES
0	0.0038	0.0039	0.0039	0	0	0
1	0.0647	0.0654	0.0654	0.0567	0.0504	0.14
2	0.0986	0.1082	0.0182	0.0875	0.084	0.14
3	0.097	0.095	0.095	0.079	0.075	0.14
4	0.0945	0.0835	0.0835	0.0726	0.069	0.13
5	0.092	0.0745	0.0745	0.0676	0.0663	0.12
6	0.0875	0.068	0.068	0.0635	0.065	0.1
7	0.082	0.0625	0.0625	0.0592	0.064	0.06
8	0.0745	0.057	0.057	0.0549	0.0605	0.05
9	0.0665	0.0515	0.0515	0.0506	0.055	0.04
10	0.0565	0.046	0.046	0.0463	0.0495	0.03
11	0.046	0.0405	0.0405	0.042	0.044	0.02
12	0.0345	0.035	0.035	0.0377	0.0385	0.015
13	0.0255	0.0295	0.0295	0.0334	0.033	0.01
14	0.0185	0.025	0.025	0.0298	0.0295	0.005
15	0.014	0.0225	0.0225	0.0278	0.0276	0
16	0.0105	0.02	0.02	0.0258	0.0259	0
17	0.0079	0.0175	0.0175	0.0238	0.0242	0
18	0.006	0.015	0.015	0.0218	0.0225	0
19	0.004	0.0129	0.0129	0.0198	0.0208	0
20	0.003	0.0111	0.0111	0.0167	0.0191	0
21	0.003	0.0111	0.0111	0.0167	0.0174	0
22	0.003	0.0111	0.0111	0.0167	0.0157	0
23	0.003	0.0111	0.0111	0.0167	0.0145	0
24	0.003	0.0111	0.0111	0.0167	0.0143	0
25	0.003	0.0111	0.0111	0.0167	0.0143	0

The figures in Table 6-8 were taken from Ref. 36, which was published by the California Air Resources Board.

Table 6-9. COMPOSITE EXHAUST EMISSIONS FOR MOTOR VEHICLES, BASED ON DATA OF TABLES 6-5, 6-6, 6-7, and 6-8

POLLUTANT	POPULATION-AVERAGED EXHAUST EMISSIONS (g/mile)					
	LDP	LDT	MDT	HDGT	HDDT	MCY
NO_x	1.175	1.78	1.91	6.795	15.26	0.76
HC	1.56	1.665	1.685	5.00	4.00	4.43

The above figures were used to calculate projected vehicle emissions for the year 2000.

Abbreviations:

LDP: Light-Duty Passenger Vehicle
LDT: Light-Duty Truck
MDT: Medium-Duty Truck
HDGT: Heavy-Duty Gasoline Truck
HDDT: Heavy-Duty Diesel Truck
MCY: Motorcycle

compounds - formaldehyde, higher aldehydes, methanol, ethylene, higher olefins, alkanes (excluding methane), and aromatics.

The composition of stationary-source emissions in 2000 was assumed to be the same as it had been in 1974. The composition data are normally compiled by the California Air Resources Board (CARB). More recent data from the 1979 inventory were not available from the CARB. The only exception was for emissions due to solvent usage, whose composition in the year 2000 we estimated on the basis of the best available information.

The composition of vehicle exhaust and evaporative reactive organic emissions which we assumed in our calculations is given in Tables 6-12 and 6-13. The figures for gasoline-fueled vehicles equipped with three-way catalysts were based on the data given in Reference 27, which were the best figures that were available. The instruments used by the authors of Reference 27 were probably not sufficiently sensitive to the presence of aldehydes. Apparently the concentration of aldehydes in the exhaust from gasoline-fueled vehicles equipped with three-way catalytic converters is fairly low. Data reported by Cadle, Nebel, and Williams at the General Motors Research Laboratories would appear to support that view (SAE Paper No. 790694). They measured the mass of aldehydes in the exhaust of five gasoline-fueled vehicles which were equipped with three-way catalysts. The average value of aldehyde emissions was 5 milligrams per mile (mg/mile), and the maximum value was 7 mg/mile. Those figures, though finite, are relatively small.

Table 6-10. EXHAUST EMISSIONS FROM MOTOR VEHICLES IN YEAR 2000 CALCULATION FOR CMAP INVENTORY

VEHICLE TYPE	PROJECTED POPULATION IN YEAR 2000 FROM REF. 43	MEAN ANNUAL MILEAGE FROM REF. 43	EMISSIONS			
			NO_x (g/mile)	NO_x (t/day)	ROC (g/mile)	ROC (t/day)
LDP						
Gasoline-Fueled	5,703,500	10,750	1.175	217.4	1.56	288.7
Diesel-Fueled	1,006,500	10,750	1.175	38.4	1.56	50.9
LDT						
Gasoline-Fueled	773,500	10,800	1.78	44.9	1.665	42.0
Diesel-Fueled	136,500	10,800	1.78	7.9	1.665	7.4
MDT						
Gasoline-Fueled	391,000	10,720	1.91	24.2	1.685	21.3
Diesel-Fueled	69,000	10,720	1.91	4.3	1.685	3.8
HDT						
Gasoline-Fueled	131,000	13,100	6.80	35.2	5.0	25.9
Diesel-Fueled	61,000	52,690	15.26	148.0	4.00	38.8
MCY	410,000	2,140	0.76	2.0	4.43	11.7
EXHAUST EMISSIONS OF GASOLINE-FUELED VEHICLES				323.7		389.6
EXHAUST EMISSIONS OF DIESEL-FUELED VEHICLES				198.6		100.9
TOTAL				522.3		490.5

Abreviations

LDP: Light-Duty Passenger Vehicle
LDT: Light-Duty Truck
MDT: Medium-Duty Truck
HDT: Heavy-Duty Truck
ROC: Reactive Organic Compounds
CMAP: California Methanol Assessment Project.

c. Methanol-Case Inventories. The substitution of methanol for petroleum-derived fuels was considered under five different sets of assumptions, which we designated as Cases A through E. Thus it was possible to note the practical implications of different policies or changes in technology. The Case E inventory was not used for any air-quality modeling calculations, it was only used to examine the possible effect of methanol substitution on emissions of sulfur oxides.

Table 6-11. EVAPORATIVE EMISSIONS FROM MOTOR VEHICLES

VEHICLE TYPE	PROJECTED NUMBER OF GASOLINE-FUELED VEHICLES	DUIRNAL (g/day)	HOT SOAK (g/trip)	NUMBER OF TRIPS PER DAY Data from Ref. 48	EMISSIONS (t/day ROC)
LDP	5,703,500	1.0	1.0	3.94	31.0
LDT	1,006,500	1.0	1.0	3.94	5.5
MDT	391,000	1.0	1.0	3.94	2.1
HDGT	131,000	0.25	1.75	9.5	2.4
MCY	410,000	11.3	4.8	0.57	6.3
TOTAL EVAPORATIVE EMISSIONS					47.3

Explanatory Notes for Table 6-11;

- Diurnal evaporative emissions are continuous emissions from the vehicle, which occur regardless of whether the vehicle is driven.

- Hot-Soak emissions occur when the vehicle engine stops running, and thus depend on the number of trips traveled by the vehicle.

Abbreviations:

LDP:	Light-Duty Passenger Vehicle	LDT:	Light-Duty Truck
MDT:	Medium-Duty Truck	HDGT:	Heavy-Duty Gasoline Truck
HDDT:	Heavy-Duty Diesel Truck	MCY:	Motorcycle

The emission inventories for Cases A through D differed from the Base-Case inventory data with respect to four main sources:

- Exhaust emissions from spark-ignited-engine vehicles.
- Evaporative Emissions from spark-ignited-engine vehicles.
- Emissions from petroleum refineries.
- Emissions due to storage and transfer of fuel.

The procedures by which those emissions were estimated will be described later. Emissions from all other sources were assumed to be unaffected by the substitution of methanol for petroleum-based motor fuels. In all cases, we assumed that methanol would not be used in diesel vehicles. We made that stipulation partly to simplify the emission-inventory calculations, and partly because the analysis in Chapter 8 of this report has indicated that the cost of methanol fuel would not become competitive with diesel fuel for a long time to come. A rough calculation showed that the overall results of our modeling calculations were not particularly sensitive to the assumption that methanol would not be used in diesel vehicles.

Table 6-12. COMPOSITION OF EXHAUST, REACTIVE ORGANIC EMISSIONS FROM CATALYST-EQUIPPED VEHICLES (Percentages by Weight)

REACTIVE ORGANIC CLASS	TYPE OF FUEL			
	GASOLINE			
	REGULAR UNLEADED WINTER GASOLINE RVP=12.3	PREMIUM UNLEADED SUMMER GASOLINE RVP=9.8	AVERAGE	METHANOL
Formaldehyde	-	-	-	21.2
Higher Aldehydes	-	-	-	-
Aromatics	20.2	40.8	30.5	-
Ethylene	8.8	5.2	7.0	-
Higher Olefins	12.5	9.7	11.1	-
Alkanes	58.7	44.3	51.5	6.1
Methanol	-	-	-	72.7

Reactive Organic Emissions include all organic compounds except methane and acetylene.

Table 6-13. COMPOSITION OF EVAPORATIVE EMISSIONS FROM LIGHT-DUTY VEHICLES (Percentages by Weight)

REACTIVE ORGANIC CLASS	TYPE OF FUEL			
	GASOLINE			
	REGULAR UNLEADED WINTER GASOLINE RVP=12.3	PREMIUM UNLEADED SUMMER GASOLINE RVP=9.8	AVERAGE	METHANOL
Formaldehyde	-	-	-	-
Higher Aldehydes	-	-	-	-
Aromatics	2.4	34.8	18.6	-
Ethylene	-	-	-	-
Higher Olefins	7.1	8.1	7.6	-
Alkanes	90.4	57.1	73.75	77.8
Methanol	-	-	-	22.2

Reactive Organic Emissions include all organic compounds except methane and acetylene.

NOTE: In Tables 6-12 and 6-13, data for gasoline were obtained from Reference 27. Data for methanol were based on calculations described elsewhere in this report.

Case A. Substitution of methanol-fueled vehicles for all gasoline-fueled vehicles on the assumption that total, lifetime-average exhaust emissions for methanol-fueled vehicles and gasoline-fueled vehicles are equal. Calculation based on SCAQMD-projected emission inventory for the year 2000.

The assumption of 100 percent substitution was intended only to establish limits, and not to suggest that such substitution was possible or desirable. This case represented the basic calculation, in which we assumed that both gasoline-fueled vehicles and methanol-fueled vehicles, designed to satisfy mandated emissions standards for new vehicles, would have the same average lifetime emissions. That very conservative assumption was made because there was not yet sufficient information to allow accurate prediction of emissions from commercial methanol-fueled vehicles in future years. Currently, the California Energy Commission (CEC) is financing fleet tests of methanol-fueled vehicles built by the Ford Motor Company and by Volkswagen of America. The CEC fleet program is intended to provide information on, among other things, the relationship between emissions and age for catalyst-equipped, methanol-fueled vehicles. That information is not yet available.

Case B. Substitution of methanol-fueled vehicles for gasoline-fueled vehicles on the assumption that total, lifetime-average exhaust emissions of reactive organic gases for methanol-fueled vehicles and gasoline-fueled vehicles are equal, but that the methanol-fueled vehicles have lower emissions of oxides of nitrogen (NO_x) than the gasoline-fueled vehicles. Calculation based on SCAQMD-projected emission inventory for the year 2000.

Several modeling calculations were made under Case B. We made one series of calculations for different values from 0 percent to 100 percent for percentage substitution of methanol-fueled vehicles for gasoline-fueled vehicles, assuming that NO_x emmissions from methanol-fueled vehicles were 50 percent lower than the corresponding emissions from gasoline-fueled vehicles. We also made another series of modeling calculations in which NO_x emissions from methanol-fueled vehicles ranged from 33 percent to 100 percent of corresponding gasoline-vehicle emissions.

These calculations were made in recognition of the well-known fact that methanol-fueled engines produce inherently lower emissions of NO_x than gasoline-fueled engines. More information about emissions from methanol-fueled engines is available in Chapter 8 of this report. In general, however, reductions in emissions from motor vehicles burning the same fuel are achieved at the expense of fuel economy. Under the prevailing system of regulations, there are no incentives to promote the lowering of emissions below the prescribed levels. Thus the calculations based on lower emissions of NO_x were intended to show what could happen, and not what would necessarily happen.

Case C. Substitution of methanol-fueled vehicles for all gasoline fueled vehicles on the assumption that total, lifetime-average exhaust emissions of nitrogen oxides and of reactive organic gases for methanol-fueled vehicles are 50 percent lower than corresponding

emissions from gasoline-fueled vehicles. Calculation based on SCAQMD-projected emission inventory for the year 2000.

The assumption of lower overall emissions for methanol-fueled vehicles can be justified on several grounds. First, more effective catalysts can be developed for methanol-fueled-vehicle exhaust because methanol and formaldehyde are more easily oxidized by exhaust catalysts than are the reactive organic compounds in gasoline exhaust, such as aromatics and alkanes. Second, there is good reason to expect that exhaust catalysts for methanol-fueled exhaust would give longer useful service because of the lower temperature of the engine exhaust and lower heat of reaction of the oxidation reaction of the unburned fuel in the exhaust catalyst. Matsumoto, et al. (Ref 42), in a failure analysis of the catalytic emission-control system of a four-cylinder, 2.2-liter Toyota, had concluded that the most probable cause of damage to the catalyst was overheating. Lastly, unpublished data obtained by researchers at the Solar Energy Research Institute suggest that vehicles utilizing the emerging technology based on the catalytic dissociation of methanol to give hydrogen and carbon monoxide would produce lower emissions of the reactive organic compounds and oxides of nitrogen than conventional vehicles.

Case D. Substitution of methanol-fueled vehicles for all gasoline-fueled vehicles on the assumption that total, lifetime-average exhaust emissions for methanol-fueled vehicles and gasoline-fueled vehicles are equal. Calculation based on CMAP-projected emission inventory for the year 2000.

This case was very similar to Case A, except that we used our (CMAP) emission inventory for Case D.

Case E. Substitution of methanol-fueled vehicles for all gasoline-fueled vehicles on the assumption that total, lifetime-average exhaust emissions for methanol-fueled vehicles and gasoline-fueled vehicles are equal, and substitution of methanol for petroleum-derived fuels in utility boilers, industrial boilers, and other boilers. Calculation based on SCAQMD-projected emission inventory for the year 2000.

This case was only examined for the likely changes in the concentrations of sulfur dioxide, sulfates, and particulates. The possible impact of methanol on those pollutants is described elsewhere in this chapter. No air-quality modeling calculations were performed using the Case E inventory.

Method of Estimation of Methanol-Case Emissions. The mass of exhaust emissions from methanol-fueled vehicles was estimated as described for each of Cases A to D above. The composition of exhaust emissions from methanol-fueled vehicles is given in Table 6-12 and is based on the results reported in references 39 and 40 which were published by the California Air Resources Board. The data were taken for Ford Escort vehicles fueled with methanol containing 5.5 percent by weight of isopentane. The response of methanol in the standard flame ionization detector (FID) was allowed for. The

figure for methanol in Table 6-12 is based on the actual molecular weight of methanol, which includes the weight of the oxygen atom. The figure used for the percentage of formaldehyde in methanol-fueled vehicle exhaust was actually a very conservative estimate based on the CEC fleet-test data. Formaldehyde emissions as low as 0.02 g/mile, corresponding to 6.1 percent in Table 6-12, have been recorded for the CEC fleet vehicles.

The mass of evaporative emissions from methanol-fueled vehicles was always assumed to be equal to the mass of evaporative emissions from gasoline-fueled vehicles. The composition of those emissions was estimated using the calculation described below.

The substitution of methanol for petroleum-based motor fuels would also effect emissions from refineries. We assumed that a 1 percent reduction in the consumption of gasoline in the South Coast Air Basin would result in a 0.4 percent reduction in basin-wide refinery throughput and emissions. This assumption was made after consulting with personnel from a petroleum company.

Evaporative emissions from petroleum storage, marketing, and transfer would also be affected by the substitution of methanol for gasoline. The emissions due to storage, marketing, and transfer of methanol were estimated from corresponding data of gasoline emissions. We estimated that gasoline-related evaporative emissions accounted for about 75 percent of all basin-wide evaporative emissions due to the storage, marketing, and transfer of petroleum products and, therefore, that petroleum-related evaporative emissions from stationary sources would be reduced by 0.75% for every 1% reduction in the use of gasoline. Emissions from all other stationary sources were assumed to be unaffected by the substitution of methanol for petroleum-based motor fuels. We estimated the evaporative losses of methanol by using the ratio of the vapor pressures of methanol fuel and gasoline at 68°F and multiplying by a factor of 1.8. The multiplying factor was based on the assumption that each gallon of gasoline would be replaced by about 1.8 gallons of methanol fuel. For the purpose of calculating vapor pressure, methanol fuel was defined as 94.5 percent methanol and 5.5 percent isopentane by weight: the composition of the fuel used in the California Energy Commission's test-fleet vehicles. The isopentane is used as a cold-start aid. Clearly, isopentane is not the only organic compound which could be used as a cold-start aid with methanol. Whatever cold start aid is used, however, is likely to have similar photochemical reactivity to that of isopentane and, in any case, the total amount of cold-start aid would be relatively small. Therefore the accuracy of the modeling results is not sensitive to our choice of cold-start aid.

Methanol-fuel (methanol plus isopentane) evaporative emissions were estimated by the following formula:

$$\text{lb moles methanol fuel evaporation} = (\text{lb moles gasoline evaporation}) \times \frac{(\text{vap. press. methanol fuel})}{(\text{vap. press. gasoline})} \times 1.8$$

where the lb moles of gasoline evaporation were taken from the data for the base case, and the vapor pressures of gasoline and methanol fuel were calculated at the temperature of 68°F.

The vapor pressure and composition of methanol fuel at 68°F were not available from direct measurement, and so we used an approximation based on the known vapor pressure of methanol at 100°F. The vapor pressure of a liquid fuel at 100°F is known as the Reid Vapor Pressure (RVP). The RVP of methanol-fuel was quoted by Volkswagen of America to be 10.0 psia. The composition of liquid methanol-fuel is 94.5% methanol and 5.5% isopentane by weight. This composition corresponds to 97.48 mole-percent methanol and 2.52 mole-percent isopentane. At 100°F the vapor pressure (VP) of pure methanol is 4.60 psia. At 68°F it is 1.92 psia. Liquid methanol fuel is a non-ideal mixture in that it has a vapor pressure which is higher than that expected from Raoult's Law. For non-ideal solutions we define activity coefficients, γ_i, for the ith solute, and γ_o, for the solvent such that the partial pressure of the solvent, p_0, is related to the vapor pressure of the pure solvent, p_o^o, by the equation

$$p_o = x_o \times \gamma_o \times p_o^o \tag{1}$$

and the partial pressure of the solute is given by

$$p_i = x_i \times \gamma_i \times K_i \tag{2}$$

where K_i is the Henry's Law constant for a very dilute (and thus nearly ideal) solution of i in the solvent and the x's are molar concentrations. In this case methanol is the solvent (subscript o) and isopentane is the solute (subscript 1).

With $x_o \approx 1.0$, we may assume that $\gamma_o \approx 1.0$. Then at 100°F

$$p_o = x_o \times P_o^o = 4.48$$

which gives:

$$p_1 = P - p_o = 5.52 \text{ psia}$$

where P is the total pressure. From equation (2) we calculate that $\gamma_1 K_1 = 219$. It is fair to assume that the activity coefficient of isopentane in dilute solution with methanol does not change appreciably between 68°F and 100°F. On the other hand K_1 does decrease exponentially with temperature. To a good approximation, the value of K_1 at temperature T_2 can be calculated from the value at temperature T_1 using the relation

$$\frac{K_{1T_2}}{K_{1T_1}} = \exp\left[-\frac{L}{R}\left(\frac{1}{T_1} - \frac{1}{T_2}\right)\right]$$

where

L is the latent heat of vaporization and R is the universal gas constant. The value of L for isopentane is 27,093 kilojoules per kilogram mole. R is 8.3143 kilojoules per kilogram mole per degree Kelvin.

Thus the value of $\gamma_i K_i$ at 68°F was estimated at 116. The partial pressure of methanol at 68°F was calculated from the vapor pressure of pure methanol at that temperature using equation (1). The results of the calculations were:

p_0 = 1.87 psia, p_1 = 2.92 psia, P = 4.79 psia = Total pressure

Thus the composition of the vapor in equilibrium with methanol fuel at 68°F was found to be

methanol - 39.0 mole percent and isopentane - 61.0 mole percent or
methanol - 22.2 weight percent and isopentane - 77.8 weight percent

At 68°F the vapor pressure of winter gasoline (RVP = 11 psia) F is about 5.4 psia and the vapor pressure of summer gasoline is about 6.6 psia. These figures were provided by the ARCO Technical Center. In our calculations we used the average of the two values, i.e., 6.0 psia. Then we obtained

lb moles of emissions from methanol fuel

= (lb moles of gasoline emissions) x 1.8 x 0.798

The mean molecular weight of methanol fuel vapor, based on the molar composition at 68°F, was 56.4. The mean molecular weight of gasoline vapor at the same temperature was estimated as 58.5 using data from Reference 42. Thus we were able to estimate the tonnage and composition of the emissions of reactive hydrocarbons of methanol-fuel as a result of storage-tank evaporation and marketing.

d. Results of Emission-Inventory Calculations. The results of the principal emission-inventory calculations are summarized in Tables 6-14 through 6-18. The figures in Table 6-18 were input into the air-quality model.

e. Sensitivity Calculations

Sensitivity of Results to Projected Mass of Highway-Vehicle Emissions. We performed modeling calculations in which we considered what would happen if highway-vehicle emissions in the year 2000 were in fact 25 or 50 percent higher than predicted by the SCAQMD.

Maximum Effect of Gasoline-Fueled-Vehicle Emissions on Ozone Levels. We set all exhaust and evaporative emissions from gasoline-fueled vehicles equal to zero in order to establish the maximum reduction in peak ozone concentration which could be achieved by any strategy to limit emissions from gasoline-fueled vehicles in the year 2000.

Table 6-14. PROJECTED EMISSIONS OF OXIDES OF NITROGEN FROM MOTOR VEHICLES IN YEAR 2000 (tons/day)

SOURCE OF EMISSIONS	CMAP PROJECTIONS		SCAQMD PROJECTIONS			
	BASE CASE	METHANOL CASE D	BASE CASE	METHANOL CASE A	METHANOL CASE B	METHANOL CASE C
EXHAUST EMISSIONS						
Gasoline-Fueled Vehicles						
LDP	217	-	163	-	-	-
LDT and MDT	69	-	53	-	-	-
HDT	35	-	30	-	-	-
MCY	2	-	2	-	-	-
Diesel-Fueled Vehicles						
LDP	38	38	29	29	29	29
LDT and MDT	12	12	9	9	9	9
HDT	148	148	128	128	128	128
Methanol-Fueled Vehicles						
LDP	-	217	-	163	82	82
LDT and MDT	-	69	-	53	27	27
HDT	-	35	-	30	15	15
MCY	-	2	-	2	1	1
TOTAL	521	521	414	414	291	291

Abbreviations:
SCAQMD - South Coast Air Quality Management District.
CMAP - California Methanol Assessment Project (this project).

Photochemical Reactivity of Methanol. In order to estimate the effect of methanol on the chemistry of the environment, we arbitrarily set the mass of emissions of methanol in "Methanol Inventory Case A" equal to zero. The resulting inventory data were used to perform a modeling calculation, whose results were then compared with those obtained using the "Methanol Inventory Case A."

Table 6-15. PROJECTED EMISSIONS OF REACTIVE ORGANIC COMPOUNDS FROM MOTOR VEHICLES IN YEAR 2000 (Tons/Day)

SOURCE OF EMISSIONS	CMAP PROJECTIONS		SCAQMD PROJECTIONS			
	BASE CASE	METHANOL CASE D	BASE CASE	METHANOL CASE A	METHANOL CASE B	METHANOL CASE C
EXHAUST EMISSIONS						
Gasoline-Fueled Vehicles						
LDP	289	-	217	-	-	-
LDT and MDT	63	-	47	-	-	-
HDT	26	-	8	-	-	-
MCY	12	-	5	-	-	-
Diesel-Fueled Vehicles						
LDP	51	51	38	38	38	38
LDT and MDT	11	11	8	8	8	8
HDT	39	39	14	14	14	14
Methanol-Fueled Vehicles						
LDP	-	289	-	217	217	109
LDT and MDT	-	63	-	47	47	24
HDT	-	26	-	8	8	4
MCY	-	12	-	5	5	3
EVAP. EMISSIONS						
Gasoline-Fueled	47	-	32	-	-	-
Methanol-Fueled	-	47	-	32	32	32
TOTAL	538	538	369	369	369	232

Abbreviations:

SCAQMD - South Coast Air Quality Management District.
CMAP - California Methanol Assessment Project (this project).

Table 6-16. PROJECTED PETROLEUM-RELATED STATIONARY-SOURCE EMISSIONS IN THE YEAR 2000, REACTIVE ORGANIC COMPOUNDS (Tons/Day)

SOURCE OF EMISSIONS	CMAP		SCAQMD		
	BASE CASE	METHANOL CASE D	BASE CASE	METHANOL CASES A & B	METHANOL CASE C
Petroleum Production	45	45	45	45	45
Petroleum Refinery	53	32	53	32	32
Fuel Marketing, Storage, Transfer					
Petroleum-Related	71	18	71	18	18
Methanol-Related	-	77	-	77	77
TOTAL	169	172	169	172	172

Table 6-17. PROJECTED PETROLEUM-RELATED STATIONARY-SOURCE EMISSIONS IN THE YEAR 2000, OXIDES OF NITROGEN (Tons/Day)

SOURCE OF EMISSIONS	CMAP		SCAQMD		
	BASE CASE	METHANOL CASE D	BASE CASE	METHANOL CASES A & B	METHANOL CASE C
Petroleum Production	2	2	2	2	2
Petroleum Refinery	71	43	71	43	43
Fuel Marketing & Storage	-	-	-	-	-
TOTAL	73	45	73	45	45

Explanatory Notes for Tables 6-14 and 6-18: Methanol Cases A, B, C, and D all refer to 100% substitution of methanol for petroleum-based fuel. Data for other levels of substitution are given by simple linear interpolation between the base case and the methanol case.

CASE A: Substitution of methanol for gasoline on the assumption that total exhaust emissions for methanol-fueled vehicles and gasoline-fueled vehicles are equal. Calculations based on SCAQMD inventory.

CASE B: Substitution of methanol for gasoline on the assumption that hydrocarbon exhaust emissions for methanol-fueled vehicles and gasoline-fueled vehicles are equal, no NO_x exhaust emissions for methanol-fueled vehicles are 50% lower than emissions from gasoline-fueled vehicles. Calculations based on SCAQMD inventory.

CASE C: Substitution of methanol for gasoline on the assumption that both hydrocarbon and NO_x emissions for methanol-fueled vehicles are 50% lower than emissions from gasoline-fueled vehicles. Calculations based on SCAQMD inventory.

CASE D: Substitution of methanol for gasoline on the assumption that total exhaust emissions for methanol-fueled vehicles and gasoline-fueled vehicles are equal. Calculations based on CMAP inventory.

Table 6-18. TOTAL EMISSIONS BY REACTIVITY CLASS, FOR DIFFERENT BASE CASES AND METHANOL CASES (Tons/Day)

COMPOUNDS	BASE CASES		METHANOL CASES			
			SCAQMD INVENTORY			CMAP INVENTORY
	SCAQMD	CMAP	CASE A	CASE B	CASE C	CASE D
Formaldehyde	16.6	17.3	74.7	74.7	32.8	64.0
Other Aldehydes	36.4	37.2	36.4	36.4	36.4	37.2
Aromatics	208.7	251.1	113.2	113.2	113.2	118.4
Ethylene	41.9	53.2	22.3	22.3	22.3	25.6
Olefins	80.0	101.6	41.9	41.9	41.9	49.8
Alkanes	704.8	797.1	576.9	576.9	568.5	618.4
Methanol	0	0	225.7	225.7	137.5	346.6
Oxides of Nitrogen	920	990	892	768	768	999

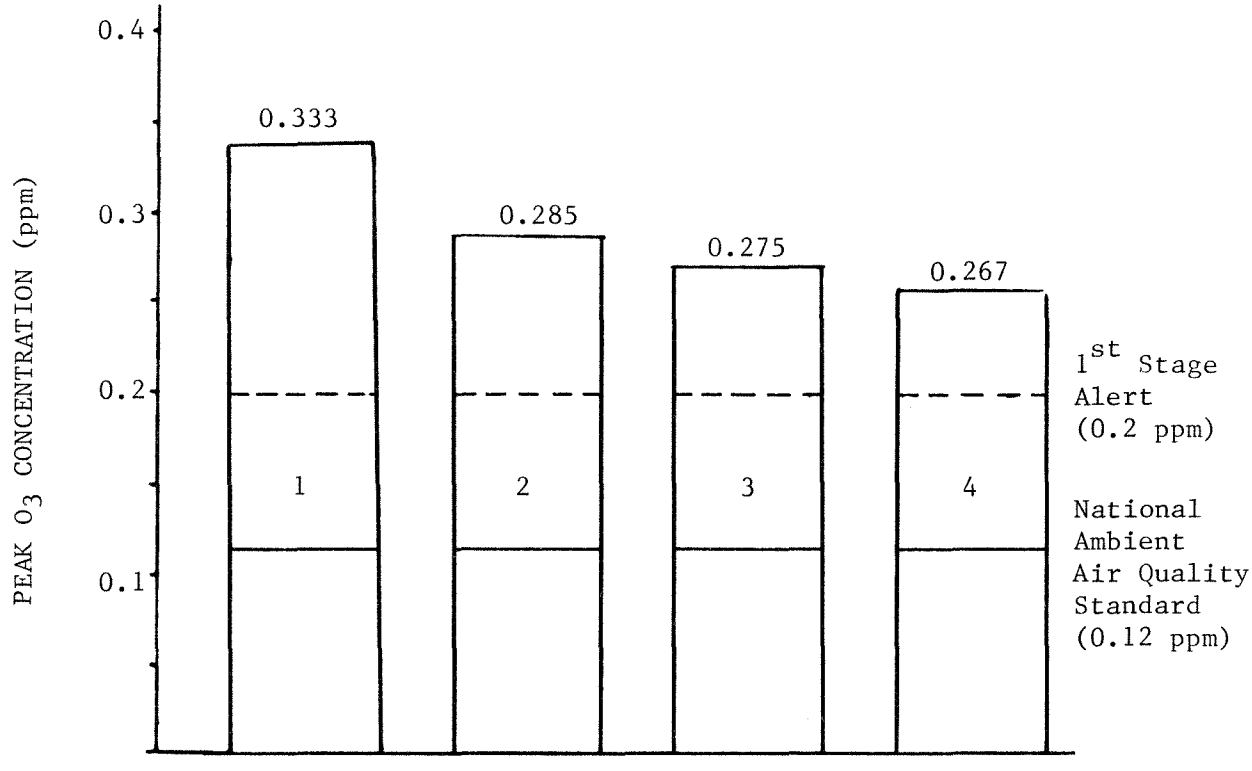
The base cases and methanol cases were defined in the text of this chapter.

4. Results of Modeling Calculations

a. Ozone Concentrations. We used the model to estimate the expected changes in ambient concentrations of ozone, formaldehyde, PAN, and nitrogen dioxide. Our calculations were made for the trajectory of an air parcel traversing the air basin and passing through Upland at 4:00 p.m. The meteorological conditions were those which existed on June 28, 1974. On that day, air quality was particularly poor, with a peak ozone concentration of 0.38 part per million (ppm) at 3:00 p.m. in Azusa. When the model was used with the 1974 emissions as inputs, the indicated peak concentration of ozone for the Upland trajectory of June 28, 1974 was 0.37 ppm. The model had previously been validated for June 28 (see Ref. 63).

Figure 6-3 shows the peak ozone concentrations for four different cases. The results indicate that substitution of methanol for gasoline as a fuel for highway vehicles would result in substantial reductions in levels of ozone and peroxyacyl nitrates (PAN). The four peaks shown in Figure 6-3 are as follows:

(1) Peak 1 shows the daily maximum ozone concentration for the base case in which gasoline is used as the fuel for all the conven-



Legend:

1. Based on SCAQMD Projection of Emissions for Year 2000.

2. Complete Substitution of Methanol for Gasoline, based on SCAQMD Projection of Emissions for Year 2000 (Methanol Case A).

3. Complete Substitution of Methanol for Gasoline, based on SCAQMD Projection of Emissions for Year 2000, with Methanol Vehicles Having 50% of NO_x Emissions of Gasoline Vehicles (Methanol Case B).

4. Complete Substitution of Methanol for Gasoline, Based on SCAQMD Projection of Emissions for Year 2000, with Methanol Vehicles Having 50% of NO_x and HC Emissions of Gasoline Vehicles (Methanol Case C).

Figure 6-3. PEAK OZONE CONCENTRATIONS FOR VARIOUS EMISSION LEVELS

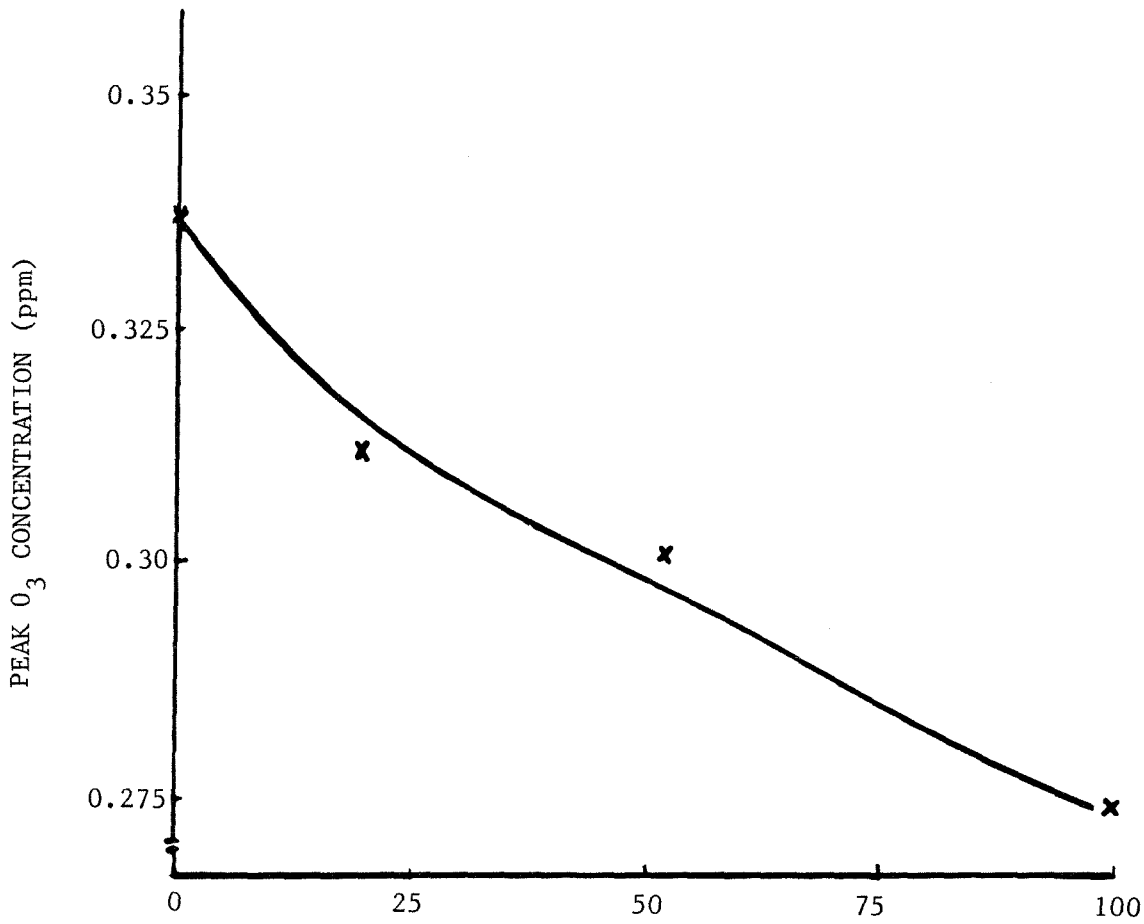
tional, spark-ignited-engine vehicles in the South Coast Air Basin in the year 2000. The vehicle emissions for the year 2000 were estimated by the South Coast Air Quality Management District (SCAQMD) and published in the Revised 1982 Air Quality Management Plan. The peak level of ozone was 0.333 ppm and the peak level of PAN was 0.033 ppm.

(2) Peak 2 shows the ozone concentration for the Case A methanol inventory in which we assumed complete substitution of methanol for gasoline in the year 2000 with total emissions of reactive organic compounds and of oxides of nitrogen from methanol-fueled vehicles being equal to the corresponding emissions for gasoline-fueled vehicles. Please note that this assumption is very conservative. The SCAQMD's projections for gasoline-fueled-vehicle emissions in the year 2000 were used in this modeling calculation. The peak ozone concentration was 0.285 ppm, which is 14.4 percent lower than the corresponding peak for the gasoline case shown in Peak 1. In addition, the peak concentration of PAN was reduced by 21.5 percent.

(3) Peak 3 shows ozone concentration for the basic Case B methanol inventory, assuming complete substitution of methanol for gasoline for all conventional, spark-ignited-engine vehicles in the year 2000, with total exhaust emissions of reactive organic compounds equal to the corresponding emissions for gasoline-fueled vehicles but emissions of NO_x 50 percent lower than for gasoline fueled vehicles. The SCAQMD's projections for gasoline-fueled-vehicle emissions in the year 2000 were used in this modeling calaculation. The peak ozone concentration was 0.275 ppm, 17.4 percent lower than the base case represented by Peak 1. The difference between Peak 2 and Peak 3 is a measure of the sensitivity of peak ozone concentration to total emissions of NO_x. Peak 3, which allowed for 50 percent lower emissions of NO_x for methanol-fueled vehicles, represented a decrease of 8.5 percent in total NO_x emissions compared with Peak 2. The corresponding difference in peak ozones between Peak 2 and Peak 3 was equal to 3.5 percent of the peak value for Peak 2.

In the Case B methanol inventory, calculations were also made for 20, 50 and 100 percent substitution of methanol for gasoline. The relationship between peak ozone concentration and percentage of fuel substitution is shown in Figure 6-4. The reduction in peak ozone concentration relative to the base case was 6.6 percent for 20 percent methanol substitution and 9.9 percent for 50 percent methanol substitution.

(4) Peak 4 in Figure 6-3 was obtained for the methanol inventory Case C, which is complete substitution of methanol for gasoline, assuming that total exhaust emissions of both NO_x and reactive organic compounds are 50 percent lower than the corresponding emissions for gasoline-fueled vehicles. The SCAQMD's projections for gasoline-fueled-vehicle emissions in the year 2000 were used in this modeling calculation. The peak level of ozone was 19.6 percent lower than the base level of Peak 1.



Based on SCAQMD Projection of Emissions for Year 2000.

Figure 6-4.

PLOT OF PEAK OZONE CONCENTRATION
VERSUS
PERCENTAGE OF HIGHWAY VEHICLES USING METHANOL

Figure 6-5 shows ozone concentration as a function of time for the base case and the methanol case, where the mass of methanol-case vehicle emissions of NO_x and reactive organic compounds were assumed to be equal to the gasoline-case emissions. The curves shown correspond to the CMAP base case and the CMAP methanol case, which is methanol Case D. The peak ozone levels for the gasoline case and the methanol case were 0.344 ppm and 0.300 ppm respectively.

When we set the mass of methanol emissions in Case A equal to zero, the resulting peak ozone concentration was 16.4 percent lower than that of the AQMP base case. By comparison, the peak ozone concentration corresponding to the Case A inventory was 14.4 percent lower than that for the AQMP base case. Thus we found, as we had expected, that the reactivity of methanol was relatively low.

Finally, we set all exhaust and evaporative emissions from gasoline-fueled vehicles equal to zero in order to establish the maximum reduction in peak ozone concentration which could be achieved by any strategy to limit emissions from gasoline-fueled vehicles in the year 2000. By comparison with the base case, the reduction in peak ozone concentration was 25 percent.

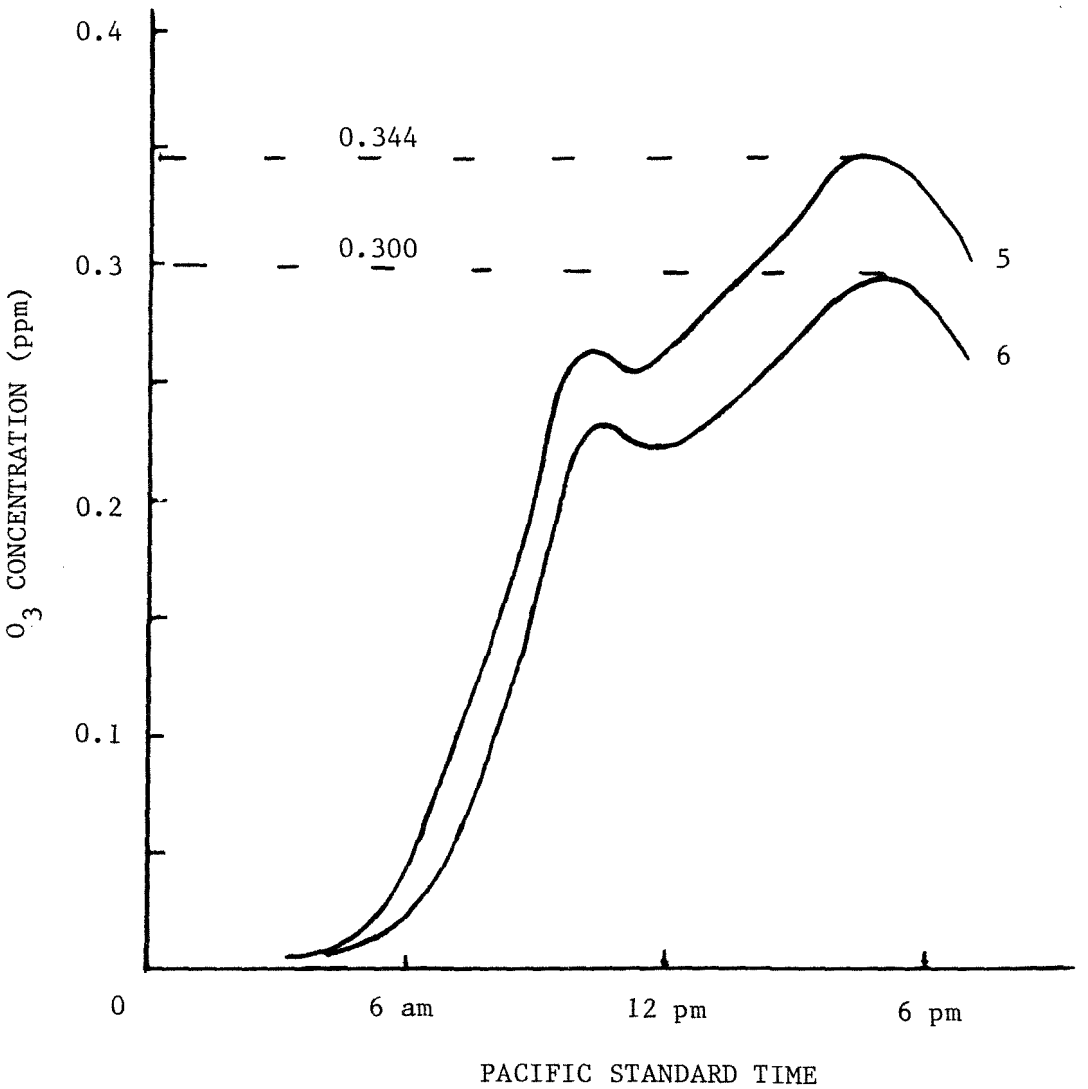
The results of the modeling calculations clearly suggest that methanol could play an important role in reducing photochemical smog in Los Angeles. The potential impact of methanol as a vehicle fuel is limited by the expected emissions from motor vehicles. The percentage contribution of highway motor vehicles to total emissions of NO_x and reactive organic compounds in 1974 was 53.3 percent and 65.0 percent, respectively. By the year 2000 total combined emissions from gasoline-fueled and diesel-fueled highway vehicles are expected to contribute 44.9 percent and 34 percent respectively to total emissions of NO_x and reactive organic compounds.

We investigated the effect of methanol-vehicle NO_x emissions on ozone concentration. The results are shown in Figure 6-6, where the percent reduction in peak ozone concentration is plotted against the assumed average mass of NO_x emissions from methanol-fueled vehicles, expressed as a fraction of the projected gasoline-vehicle emissions.

Figure 6-7 shows the results of the calculations to investigate the possible effect on peak ozone level of possible errors in the estimation of motor-vehicle emissions for the year 2000. Note that, while the absolute values of peak ozone concentrations do change, the <u>percentage</u> reduction in peak ozone as a result of methanol substitution is not particularly sensitive to changes in the mass of highway emissions.

b. <u>Formaldehyde Concentrations</u>. The air-quality model was used to predict hourly average concentrations of formaldehyde over each 5-kilometer square grid of the Basin. The peak hourly concentration of formaldehyde for a typical smoggy day was 0.0355 ppm for the base case and 0.0535 ppm for the methanol case. These concentrations are not high enough to justify general concern.

There is concern about potentially high concentrations of formaldehyde in restricted areas. Vehicles starting up from cold produce unusually high



5. Based on our (CMAP) Projection of Emissions for Year 2000.

6. Complete Substitution of Methanol for Gasoline, Based on our (CMAP) Projection of Emissions for Year 2000.

Figure 6-5. PLOT OF OZONE CONCENTRATION VS. TIME

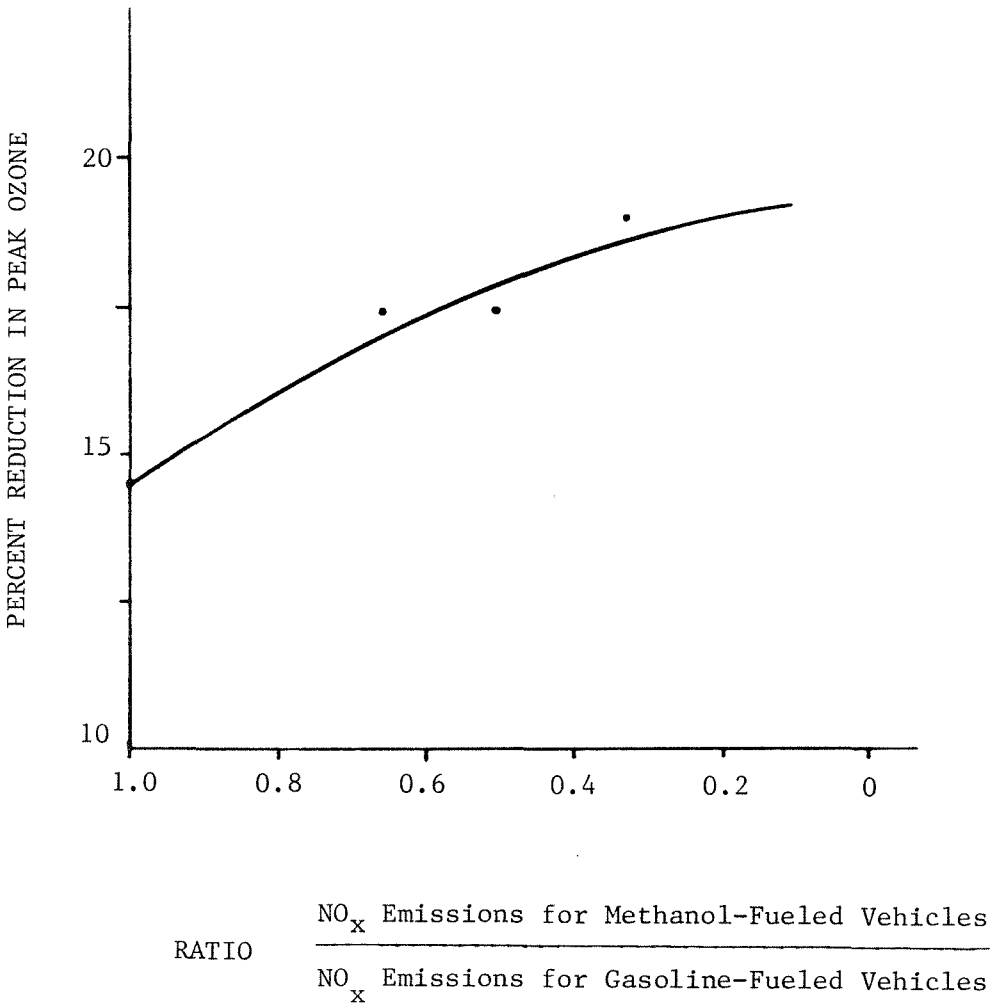
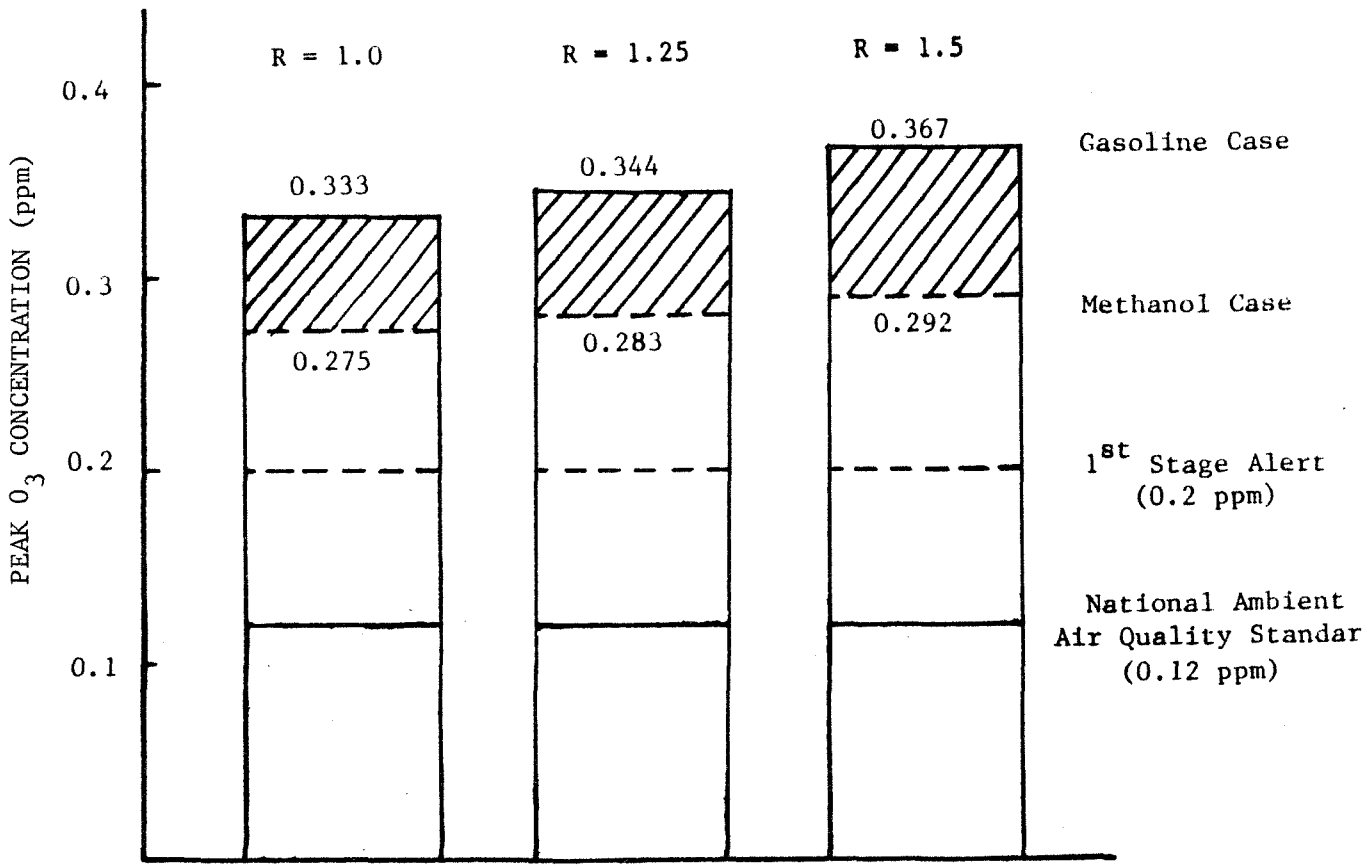


Figure 6-6. REDUCTION IN PEAK OZONE AS A FUNCTION OF NO_x EMISSIONS FOR METHANOL VEHICLES



$$R = \text{Ratio} \quad \frac{\text{Actual Highway Vehicle Emissions in Year 2000}}{\text{SCAQMD-Projected Highway Vehicle Emissions in Year 2000}}$$

Notes:

1. Methanol was assumed to be substituted for gasoline but not for diesel.
2. Mass of exhaust emissions for methanol vehicles:

   Hydrocarbons -- same as for gasoline vehicles,
   NO_x -- 50% lower than for gasoline vehicles.

Figure 6-7. SENSITIVITY OF OZONE PEAK TO PROJECTED EMISSIONS FOR HIGHWAY VEHICLES IN THE YEAR 2000

levels of emissions of CO and organic compounds. The likely maximum concentration of formaldehyde in restricted spaces in which methanol-fueled vehicles might be operated, such as garages, can be roughly estimated using measured concentrations of CO in similarly restricted areas, such as those reported by Myronuk (Ref. 60). The calculation shows that the maximum ambient concentration of formaldehyde would be about 1 ppm. The concentration of formaldehyde would be somewhat lower in the daylight hours because formaldehyde decomposes rapidly in the presence of sunlight. More sophisticated modeling procedures could be used in order to obtain a more accurate estimate. Recently, calculations of pollutant dispersion near roads have been described by Chock at General Motors.

D. IMPACT OF METHANOL USAGE ON CONCENTRATIONS OF SULFUR COMPOUNDS AND PARTICULATES

1. Summary

In this section we describe how we estimated the likely changes in the ambient concentrations of sulfur compounds in the year 2000. Because of the very high level of uncertainty in the projected inventory of emissions for total suspended particulates, we did not use that projected inventory for any calculations.

The suspended particulates include sand, dust, non-volatile carbon (soot), sulfates, inorganic nitrates, organic nitrates, and condensible organic substances. Thus the term "total suspended particulates" (TSP) is a blanket description for a variety of chemical species in a range of particle sizes, and tells little about the impacts which those different kinds of particulates would have on the environemnt. For that reason, we did not use emission inventories for TSP in assessing the possible impact of methanol. Instead, we made a qualitative evaluation based on some published work.

According to Cass, Boone, and Macias (Ref. 46) on-road and off-road diesel engines accounted for 61.0 percent of all fine non-volatile carbon emissions in the South Coast Air Basin in 1980, while gasoline-fueled vehicles accounted for 10.2 percent. Methanol-fueled engines, on the other hand, produce very little particulate matter. The Southern California Edison Company performed combustion tests using methanol in boilers and turbines, from which they confirmed that methanol was an extremely clean-burning fuel. Pefley and his associates at the University of Santa Clara have made a similar observation from their work with methanol-fueled, spark-ignited engines. Thus if methanol were to be substituted for gasoline there would be a reduction in total emissions of non-volatile carbon. A much larger reduction in such emissions would occur if methanol were to be substituted for diesel fuel as well as gasoline.

We estimated the expected ambient concentrations of SO_x and sulfates relative to their ambient concentrations for 1979 using the "linear roll-back" approximation. That approximation assumes that the change in ambient concentrations between 1979 and the year 2000 is directly proportional to the change in the total emissions of the corresponding primary pollutants over the same period. No more sophisticated methods of calculation are available for the sulfur compounds.

Emissions of sulfur oxides were projected for the year 2000 for three cases which were described earlier in this chapter:

(1) SCAQMD Base Case
(2) Methanol Case A
(3) Methanol Case E

The methanol Case D was similar to Case A except that for Case D all utility boilers and industrial and other boilers were also assumed to be converted to methanol fuel.

2. Emission Inventory for Sulfur

Figures for the projected inventory of sulfur emissions in the year 2000 were taken directly from the Revised 1982 Air Quality Management Plan (Ref. 44). Emissions of sulfur oxides for methanol cases A and D are shown in Table 6-19.

3. Results of Calculations

Table 6-20 shows the approximate changes which would be expected in the concentrations of sulfur compounds if methanol was substituted for oil-based fuels.

Table 6-19. INVENTORY OF EMISSIONS OF SULFUR OXIDES IN THE YEAR 2000 (Tons/Day)

SOURCE	BASE CASE	METHANOL CASE A	METHANOL CASE E
STATIONARY SOURCES			
Oil and Gas Production	-	-	-
Petroleum Refinery	26	16	16
Petroleum Storage, Marketing & Transfer	-	-	-
Organic Solvent Usage	-	-	-
Metallurgical and Mineral Operations	11	11	11
Misc. Industrial Sources	2	2	2
Fuel Combustion-Power Plants	51	51	-
Industrial, Commercial & Other Boilers	27	27	-
Agricultural Sources	2	2	2
Miscellaneous Sources	-	-	-
TOTAL STATIONARY SOURCES	119	109	21

Table 6-19. INVENTORY OF EMISSIONS OF SULFUR OXIDES IN THE YEAR 2000 (Tons/Day) (Continued)

SOURCE	BASE CASE	METHANOL CASE A	METHANOL CASE E
MOBILE SOURCES			
On-Road Vehicles			
Light-Duty Passenger Auto	12	-	-
Medium & Light-Duty Trucks	6	-	-
Heavy-Duty Gasoline Trucks	3	-	-
Heavy-Duty Diesel Trucks	15	15	15
Motor Cycles	-	-	-
SUBTOTAL ON-ROAD VEHICLES	36	15	15
Other Mobile Sources			
Railroad Trains	4	4	4
Marine Craft	22	22	22
Aircraft	2	2	2
Off-Road Vehicles	1	1	1
Mobile Equipment	5	5	5
SUBTOTAL OTHER MOBILE SOURCES	34	34	34
TOTAL MOBILE SOURCES	70	49	49
TOTAL STATIONARY SOURCES	119	109	21
TOTAL EMISSIONS	189	158	70

Explanatory Notes for Tables 6-19 and 6-20:

Base Case: Projected emissions for the year 2000, as published by SCAQMD IN THE Air Quality Management Plan, 1982 revision.

Methanol Case A: Projected emissions for the year 2000 calculated as for the base case except that all gasoline-fueled vehicles assumed to be converted to methanol fuel.

Methanol Case E: Similar to Case A except that all utility boilers and industrial and other boilers also assumed to be converted to methanol fuel.

Table 6-20. EFFECT OF METHANOL SUBSTITUTION ON AMBIENT CONCENTRATIONS OF SULFUR COMPOUNDS AND PARTICULATES IN THE SOUTH COAST AIR BASIN

	APPROXIMATE CONCENTRATIONS			
		Year 2000		
	1979	BASE CASE	METHANOL CASE A	METHANOL CASE E
Sulfur Dioxide - Annual Arithmetic Mean ($\frac{\mu g}{m^3}$)	19	13.0	10.9	4.8
Sulfates - Max. 24-hr average ($\frac{\mu g}{m^3}$)	26.6	18.2	15.2	6.7
Total Suspended Particulates - Annual Arithmetic Mean ($\frac{\mu g}{m^3}$)	110	125	-	-

E. SUMMARY AND DISCUSSION

1. Physical Effects of Air Pollutants - A Qualitative Discussion

If methanol were to be substituted for petroleum-derived fuels, what would be the changes in the physical impacts of pollutants?

In this section we present a brief description of the physical impacts of different pollutants in order to give the reader a very general overview of the effects of air pollution. Table 6-21 shows the expected physical effects in the atmosphere of large-scale substitution of methanol for petroleum-derived fuels. That table is only qualitative. The references on which the physical impacts mentioned in Table 6-21 are based are summarized in Table 6-22.

Ozone causes damage to crops and to rubbers, elasomers and paints. It can also induce respiratory illness. Much of the available evidence suggests that the health effects of ozone tend to be acute rather than chronic. At concentrations below 0.15 ppm, ozone is considered to be harmless to most people. Higher concentrations of ozone can induce severe irritation of the respiratory tract and eyes, causing severe discomfort especially if the person

Table 6-21. MAXIMUM CHANGES IN AIR QUALITY DUE TO USE OF METHANOL IN SPARK-IGNITED MOTOR VEHICLES IN SOUTH COAST AIR BASIN IN THE YEAR 2000

POLLUTANT	CHANGE	PHYSICAL IMPACTS
OZONE	Reduction	-Reduced acute respiratory illness -Reduced damage to paints, elastomers, rubber -Reduced damage to crops
SULFATE	Small reduction	-Reduced mortality -Reduced acidity of rain -Improved visibility
FORMALDEHYDE	Small increase	-Possible odor -Eye irritation if local concn. high -No known health effects at low concn.
NITROGEN DIOXIDE	Small reduction	-Reduced acidity of rain -Possible reduction in respiratory illness
PEROXY ACYL NITRATES	Significant reduction	-Reduced eye irritation
TOTAL SUSPENDED PARTICULATES	Reduction	Improved visibility

Table 6-22. REFERENCES FOR PHYSICAL IMPACTS OF AIR POLLUTANTS

POLLUTANT	PHYSICAL IMPACT	REFERENCES
OZONE	-Acute respiratory illness	52
	-Damage to paints, elastomers, rubber	54
	-Damage to crops	53, 56
SULFATE	-Human mortality	50, 51
	-Acidity of rain	61
	-Reduced visibility	45, 48, 49
SULFUR DIOXIDE	-Metallic corrosion	54
	-Respiratory illness	52
FORMALDEHYDE	-Cancer in animals, at very high concns.	58, 59
	-Eye irritation	
NITROGEN DIOXIDE	-Acidity of rain	61
	-Possible respiratory illness	52, 56
TOTAL SUSPENDED PARTICULATES	-Reduced visibility	45, 46, 47

concerned is taking part in physical excercise. Among pollutants, ozone is the leading cause of damage to agricultural crops in the South Coast Air Basin. In 1971, Millecan (Ref. 53) estimated that ozone was responsible for about 50 percent of all air-pollution-related damage to crops in the Basin. The effects of any pollutant on vegetation depend on the damage to crops as well as the concentration of pollutant. In general, acute exposure and chronic exposure produce different effects. Larsen and Heck (Ref. 56) studied the effects of ozone (O_3) and sulfur dioxide (SO_2) on vegetables and trees and produced correlations between percentage of leaf injury for fifteen different agricultural crops and concentration and duration of exposure to O_3. The relationship between agricultural yield and leaf injury, however, is less well-documented. Millecan (Ref. 53) produced some figures which he used to predict the relationship between the percentage damage to leaves and the loss in crop yield. Ozone is also responsible for much of the damage to paints, rubbers, and elastomers (Ref. 54).

Formaldehyde has an irritating odor and is a suspected carcinogen. Much of the published information about the effects of formaldehyde was obtained at high concentrations. Very low-level, long-term exposures have not been well studied. In recent years, investigators have discovered that continuous exposure to high concentrations of formaldehyde causes cancer in laboratory animals. There is no consensus on whether laboratory data based on the chronic exposure of animals to very high pollutant concentrations are directly applicable to short-term, low-level exposure in man (Ref. 61). For example,

no evidence has been obtained indicating that people who work in chemical plants where formaldehyde is manufactured or processed have a higher incidence of nasal or respiratory cancer than the rest of the population.

Total suspended particulates cause loss of visibility by two main processes - light absorption and light scattering. Carbonaceous particulates derived from soot are a major cause of light absorption in Los Angeles and other cities (Ref. 46). Dust particles also absorb light to some degree. Conklin, et al. (Ref 45), analyzed wintertime air samples from the Los Angeles area and found that light absorption by elemental carbon could account for about 17 percent of the total loss of visibility in downtown Los Angeles. Unfortunately, we had insufficient data to allow us to make firm quantitative predictions about any possible improvements.

Light-scattering by particles of diameter less than 2.5 micrometers (m) is a major cause of loss of visibility in polluted areas. Such small particles arise from gas-to-particle conversion reactions in the atmosphere. The predominant species in that size range are sulfates such as ammonium sulfate, sulfuric acid, and inorganic nitrates such as sodium nitrate, ammonium nitrate, and nitric acid. Because the particle diameter of sulfates is comparable to the wave length of visible light, those particles give rise to the most effective scattering of light from the sun and thus contribute significantly to poor visibility. Studies have indicated that sulfates in the Los Angeles atmosphere may be responsible for as much as 50 percent of the light-scattering in downtown Los Angeles (Ref. 47).

The sulfate particles in the atmosphere are generally smaller than 2.5 microns in diameter and are therefore also small enough to penetrate the human lung, where they are absorbed in the mucous lining of the lungs, causing damage to the delicate tissues of the respiratory system. Further, sulfates are one of the major causes of acid rain in areas like the north-eastern United States. Sulfates have been associated with loss of visibility in cities (Ref. 48,49). Cass (Ref 45) calculated that a 75 percent reduction in sulfate levels in Los Angeles would reduce the number of days on which visibility was less than 3 miles by about two-thirds, and reduce the number of days with visibility below 10 miles by about 10 percent. Sulfates are responsible for the more serious health effects of air pollution. Mendelsohn and Orcutt (Ref 51) estimated that sulfates in the atmosphere were responsible for tens of thousands of deaths every year.

Sulfur dioxide causes illness and is the major cause of the corrosion of metallic objects in the atmosphere. Sulfur dioxide in the atmosphere has also been correlated with ill-health by Durham (Ref. 52), who studied the frequency of illness among university students in California and found that the pollutants most significantly correlated with respiratory illness were the oxidants, sulfur dioxide, and nitrogen dioxide. The most pollution-related illnesses were pharyngitis, bronchitis, tonsilitis, colds, and sore throat.

Nitrogen dioxide (NO_2) produces a yellowish haze in the sky and thus affects visibility. In addition, NO_2 can also react with vapor to form nitric-acid vapor which may affect human health. More importantly, NO_2 is a precursor of acid rain whose effects on plants and aquatic animals are only now becoming fully appreicated. Laboratory studies of animals exposed to

NO_2 have shown an increase in emphysema and cardiovascular disease (Ref. 55) and an increased susceptibility to viral infection. In the work of Durham (Ref. 52) mentioned above, NO_2 was associated with respiratory illness.

We have not attempted to quantify the economic value of the likely air-quality benefits methanol as a fuel in the South Coast Air Basin. We have simply assumed that the use of methanol will be determined by the free market, depending on the price and the utilization of efficiency of the fuel. Later, we shall briefly discuss possible mechanisms by which the use of cleaner fuels could be encouraged.

2. General Discussion

Most of the results of modeling calculations described in Section C are straight-forward. Some of them, however, require further comment.

The approximate linear relationship between the degree of methanol substitution and the peak concentration of ozone implies that the atmospheric reactions of methanol and those of the reactive components and by-products of gasoline are not significantly coupled. That observation is entirely consistent with the fact indicated elsewhere that methanol is significantly less reactive than the other reactive compounds in the atmosphere.

The reduction in peak ozone concentration with decreased NO_x emissions in the methanol case appears superficially to be at variance with the results of a recent study made by System Applications, Inc. (SAI) of San Rafael, California, on behalf of the Western Oil and Gas Association (WOGA) (see Ref. 62). Actually, the SAI/WOGA study was based on different premises from those used in the calculations described in this chapter. The results we show in Figure 6-6 refer to the case where methanol was substituted for gasoline, which was not one of the cases considered by the SAI/WOGA study. The SAI/WOGA study used a different emission inventory from that which we used. They used a projected 1987 inventory and applied to it the emission reductions expected from implementaton of some provisions of the Air Quality Management Plan (AQMP) for the South Coast Air Basin. There may also be other differences in the data used in the modeling calculations. Thus, the funding does not necessarily contradict the results of the SAI/WOGA study. It refers to a methanol case and not to a gasoline case.

The likely impact of methanol fueling on the atmospheric environment in the Los Angeles basin in the year 2000 is summarized in Table 6-21 (see p. 6-54). The major conclusion to be drawn from the information in Table 6-21 is that the use of methanol as a liquid fuel would help to improve the air quality within the South Coast Air Basin. In particular, there would be a reduction in the concentration of ozone in the Basin mainly because methanol has a lower photochemical reactivity than fuels derived from petroleum.

Methanol could form part of an effective, long-term strategy for the control of photochemical smog in Los Angeles, when used in conjunction with other emission-control strategies. An economic analysis based on the estimated price of methanol and the projected price of gasoline (described elsewhere in this report) indicated that under the most favorable circumstances, methanol-fueled vehicles could account for about 5-10 percent of all

gasoline-fueled vehicles in the Basin in the year 2000. Thus, methanol is not expected to be an effective strategy for reducing pollution in the Basin in the short term; its potential contribution to air-quality improvement is a long-term one.

Methanol also has the potential to produce lower NO_x emissions from both mobile and stationary sources. In the case of vehicle emissions, that potential is unlikely to be realized under current regulations because, in general, reductions in emissions from motor vehicles are achieved at the expense of fuel economy. The emission of NO_x from methanol-fueled vehicles illustrates this complex relationship between emission levels and fuel efficiency. When the emissions of NO_x for the methanol-fueled 1981 Ford Escorts used in the Los Angeles County fleet test were reduced from 1.0 g/mile to 0.25 g/mile, the fuel consumption increased by 26 percent.

Under the existing regulations, there are no monetary incentives for industries or individuals to reduce emissions below the levels required by law. If the use of cleaner-burning fuels is to be encouraged, then the current regulations must be reformed in order to provide such incentives. One scheme which has been suggested (Refs. 28, 29) is the system of marketable emission permits. Such a system could operate in the following way. Every 5 years or so the regulatory authorities would determine the total tonnage of allowed emissions, and divide that total among major sources of pollution such as industries, utilities, petroleum refiners, and manufacturers of vehicles (representing vehicle owners). Each of the polluting agencies would be free to limit total emissions by any means at its disposal. Any agency which reduced emissions below its allotted amount would be free to sell the unused emission permits in an open market or to offset the unused permits against future emissions. And, for example, some industry might purchase emission permits rather than spend large sums of money on retrofitting old plants. In a perfect market the going price of a permit would be equal to the marginal cost of abatement for the relevant pollutant. Thus the system of marketable emission permits would encourage innovation while maintaining flexibility within the economy. The system would affect the viability of methanol-fueled vehicles in the following way. The manufacturer of a clean-burning methanol-fueled vehicle would be free to sell any unused emission permits and pass the savings on to the buyers of methanol-fueled vehicles in the form of cash rebates. Alternatively, the lower emissions from methanol-fueled vehicles could be offset against higher emissions from other types of vehicles produced by the same manufacturer, thus producing a net saving which could be passed on to customers. The above comments are equally applicable to other clean fuels such as hydrogen, methane, and propane and also to electrically-powered vehicles.

3. Suggestions for Further Work

The work described in this chapter is only an initial investigation. The accuracy of the data used in the modeling calculations could possibly be improved. We believe, however, that our overall conclusions are substantially correct.

The air-quality modeling studies described in this report should be extended to consider the effect on air quality of using methanol-gasoline blends.

The emerging technology for the catalytic dissociation of methanol using exhaust heat from the vehicle's engine has the potential for significant reductions in motor vehicle emissions. Hard data of emissions from dissociated methanol vehicles must be obtained so that the likely impact of such vehicles on the environment may be evaluated.

There is an important need for a systematic series of smog-chamber experiments with gaseous mixtures containing methanol. The results of such experiments would help in confirming the results obtained in our modeling calculations.

Lastly, the effect of regulatory policies on the value of fuels needs to be investigated more carefully. There is also a need to estimate the value of the possible indirect economic benefits of a cleaner environment in an area such as Los Angeles.

F. CONCLUSIONS

The conclusions drawn from the air-quality modeling calculations and from the semi-quantitative analysis applied to projected emissions of sulfur are summarized below. The comments apply to the complete substitution of methanol for gasoline in the South Coast Air Basin, based on projected emissions for the year 2000.

(1) The complete substitution of methanol-fueled vehicles for gasoline-fueled vehicles would lead to a reduction of 14.4 to 20.0 percent in the peak, hourly-average concentration of ozone.

(2) The peak ozone concentration decreases approximately linearly with methanol substitution.

(3) The photochemical reactivity of methanol is relatively low. Thus when the mass of emissions of methanol in "Methanol Case A" was arbitrarily set to zero, the peak ozone concentration was reduced by only 2.3 percent.

(4) With the use of methanol fuel, the peak ozone concentration is reduced as emissions of NO_x are reduced. The ozone concentration, however, is a lot less sensitive to emissions of NO_x than to reactive organic emissions.

(5) The maximum reduction in ozone concentration achievable by elimination of gasoline-fueled-vehicle emissions is 25 percent.

(6) With methanol substitution, the ambient concentration of formaldehyde would not increase significantly.

(7) The concentration of sulfur-derived pollutants would not be significantly affected by methanol substitution. If methanol were to be used in utility boilers and in industrial and commercial boilers, then there would be a large reduction in the concentration of sulfur-derived pollutants.

(8) Total suspended particulates in general would not be greatly affected by methanol substitution. The concentration of fine, non-vehicle carbonaceous particulates, however, would be reduced slightly if methanol were substituted for gasoline. If methanol was also to be substituted for diesel fuel, the reduction in the concentration of non-vehicle carbonaceous particulates would be much larger.

The work described in this chapter began as a screening analysis to establish whether the large-scale use of methanol would have a detrimental effect on air quality in California. The analysis shows that, far from causing harm, methanol would have a very beneficial impact on air quality within the South Coast Air Basin. The potential atmospheric impact of methanol deserves to be investigated further.

G. REFERENCES

1. Dodge, M. C. and Whitten, G. Z., Aldehydes and Photochemical Smog, presented before the Division of Environmental Chemistry, American Chemical Society, New York (April 1976).

2. McRae, G. J., Goodin, W. R., and Seinfeld, J. H., "Mathematical Modeling of Photochemical Air Pollution," Final Report to the California Air Resources Board, Environmental Quality Laboratory, Report No. 18, California Institute of Technology, Pasadena, California, 1982.

3. Carter, W. P., Darnall, K. R., Graham, R. A., Winer, A. M., and Pitts, J. N. Jr., J. Phys. Chem., 83, p. 2305, 1979.

4. Atkinson, R., Darnall, K. R., Lloyd, A. C., Winer, A. M., and Pitts, J. N., Jr., Adv. Photochem., 11, p. 375, 1979.

5. Falls, A. H., and Seinfeld, J. H., Envirn. Sci. & Technol., 12, p. 1399, 1978.

6. Ito, K., and Yano, J., Dept. of Mech. Eng., Hokkaido Univ., Sapporo, Japan.

7. Taylor, W. D., Allston, T. D., Moscato, M. J., Fazekas, G. B., Kozlowski, R., and Takacs, G. A., Int. J. Chem. Kin., 12, p. 231, 1980.

8. Ravishankara, A. R. and Davis, D. D., J. Phys. Chem., 82, p. 2852, 1978.

9. Baldwin, A. C., Barker, T. R., Golden, D. M., and Hendry, D. G., J. Phys. Chem., 81, p. 2483, 1977.

10. Atkinson, R., Perry, R. A., and Pitts, J. N. Jr., J. Chem. Phys., 66, p. 1197, 1977.

11. McRae, G. J., Goodin, W. R., and Seinfeld, J. H., Atm. Environ., 16, p. 679, 1982.

12. Seinfeld, J. H., Air Pollution: Physical and Chemical Fundamentals, McGraw-Hill, Inc., New York, 1975.

13. Reynolds, S. D., Roth, P. M. and Seinfeld, J. H., Atm. Environ., 7, p. 1033, 1973.

14. Eschenroeder, A. Q., and Martinez, J. R., Adv. Chem. Series, 113, American Chemical Society, Washington, D.C., p. 101, 1972.

15. Lloyd, A. C., Lurmann, F. W., Godden, D. K., Hutchins, J. F., Eschenroeder, A. Q. and Nordseick, R. A., Environmental Research and Technology Report No. P-5287-500, Westlake Village, California, 1979.

16. Falls, A. H., and Seinfeld, J. H., Environ. Sci. Technol., 12, p. 1398, 1978.

17. McRae, G. J., and Seinfeld, J. H., "Development of a Second-Generation Mathematical Model for Urban Air Pollution - II Evaluation of Model Performance," Atm. Environ., 17, p. 501, 1983.

18. Falls, A. H., McRae, G. J., and Seinfeld, J. H., Int. J. Chemical Kinetics, 11, p. 1137, 1979.

19. Dunker, A. M., Atm. Environ., 15, p. 1155, 1981.

20. Seigneur, C., Tesche, T. W., Roth, P. M., and Reid, L. E., J. Applied Meteorology, 20, p. 50, 1981.

21. Tilden, J. W., and Seinfeld, J. H., Atm. Environ., 6, p. 1357, 1982.

22. Bechtold, R., and Pullman, J. B., "Driving Cycle Economy, Emissions and Photochemical Reactivity Using Alcohol Fuels and Gasoline," SAE Paper No. 800260, February 1980.

23. Raible, C. J., and Cox, F. W., "Chromatographic Methods of Analysis for Methanol and Ethanol in Automotive Exhuast," SAE Paper No. 790690, 1979.

24. California Air Resources Board, Engineering Evaluation Section, Mobile Source Control Division, Alcohol-Fueled Fleet Test Program, Project 3T8001, Second Interim Report, July, 1981.

25. Seinfeld, J. H., Lectures in Atmospheric Chemistry, AIChE Monograph Series, 76 No. 12, 1980.

26. Bufalini, J. J., Walter, T. A., and Bufalini, M. M., "Ozone Formation Potential of Organic Compounds," Environ. Sci and Technol., 10 (9), 1976, pp. 908-912.

27. Black, F. M., High, L. E., and Lang, J. M., "Composition of Automobile Evaporative and Tailpipe Hydrocarbon Emissions," J. Air Pollution Control Assoc., No. 30, p. 11, Nov. 1980.

28. Hahn, R. W., and Noll, R. G., "Designing a Market for Tradeable Emissions Permits," Social Science Working Paper No. 398, California Institute of Technology, Pasadena, California, July 1981.

29. White, L. J., The Regulation of Air Pollutant Emissions From Mobile Sources, Draft Publication, Graduate School of Business Administration, New York University, 1981.

30. Kirk, R. E., and Othmer, D. F., Encyclopedia of Chemical Technology, The Interscience Encyclopedia, Inc., New York, 1951.

31. Cleveland, W. S., Graedel, T. E., and Kleiner, B., Atm. Environ., 11, p. 357, 1976.

32. Hanst, P. L., and Gay, B. W., Envirn. Sci. & Technol., 11, p. 1105, 1977.

33. South Coast Air Quality Management District, Air Quality Management Plan, 1979.

34. Gross, R., "Emissions from Catalyst-Equipped California Cars - Customer Service," SAE Paper No. 800395.

35. Southern California Association of Governments, SCAG-78 Growth Forecast Policy, October 1978.

36. California Air Resources Board, Technical Services Division, Procedure and Basis for Estimating On-road Motor Vehicle Emissions, January 1980.

37. California Air Resources Board, Stationary Source Control Division, Supplement to Procedure and Basis for Estimating On-Road Motor Vehicle Emissions, June 1981.

38. California Air Resources Board, Vehicle Emissions Control Division, Final Report of the Light-Duty Vehicle Surveillance Test Program, Second Series, February 1980.

39. California Air Resources Board, Mobile Source Control Division, Alcohol-Fueled Test Program, Project 3T8001, Second Interim Report, July 1981.

40. California Air Resources Board, Mobile Source Control Division, Alcohol-Fueled Test Program, Project 3T8001, Third Interim Report, October 1981.

41. Mayrsohn, H., Crabtree, J. H., Kuramoto, M., Sothern, R. D., and Mano, S. H., "Source Reconciliation of Atmospheric Hydrocarbons in 1974," Atm. Environ., 11, 189, 1977.

42. Matsumoto, K., Matsumoto, T. and Goto, Y., "Reliability Analysis of Catalytic Converter as an Automotive Emission Control System," SAE Transactions 84, No.750178.

43. Southern California Association of Governments, Personal Communication from Millie Yamata, June 1982, based on report to be published shortly.

44. South Coast Air Quality Management District, Air Quality Management Plan, 1982 Revision, June 1982.

45. Conklin, M. H., Cass, G. R., Chu, L-C., and Macias, E. S., "Wintertime Carbonaceous Aerosols in Los Angeles; The Role of Elemental Carbon;" Macias, E. S., and Hopke, P., (Eds.) "Chemical Composition of Atmospheric Aerosols; Source/Air Quality Relationships," American Chemical Society, Washington, D.C., 1981.

46. Cass, G. R., Boone, P. M., and Macias, E. S., "Emissions and Air Quality Relationships for Atmospheric Carbon Particles in Los Angeles;" Wolff, G. T. and Klimisch, R. L. (Eds.) Particulate Carbon: Atmospheric Life Cycle, Plenum Publishing Corporation, 1982, White, W. H., and Roberts, P. T., "On the Nature and Origins of Visibility-Reducing Aerosols in the Los Angeles Air Basin," Atm. Environ., 12, 779-784, 1977.

47. Cass, G. R., "On the Relationship Between Sulfate Air Quality and Visibility with Examples in Los Angeles," Atm. Environ., 113, pp. 1069-1084, 1979.

48. Trijonis, J., and Yuan, K., Visibility in the Northeast: Long-Term Visibility Trends and Visibility-Pollutant Relationships, U.S. Environmental Protection Agency, Document EPA-600/3-78-075, 1978.

49. Trijonis, J., and Yuan, K., Visibility in the Southwest: An Exploration of the Historical Data Base, U.S. Environmental Protection Agency, Document EPA-600/3-78-039, 1978.

50. Lave, L. B., and Seskin, E. P., Air Pollution and Human Health, Johns Hopkins University Press, Baltimore, 1977.

51. Mendelsohn, R., "An Economic Analysis of Air Pollution from Coal-Fired Power Plants," J. Environ. Econ. and Management, 7, PP. 30-43, 1980.

52. Durham, W. E., "Air Pollution and Student Health," Archives of Environmental Health, 28, pp. 241-254, May 1974.

53. Millecan, A. A., A Survey and Assessment of Air Pollution Damage to California Vegetation in 1979, California Department of Agriculture, 1971.

54. U.S. Environmental Protection Agency, Methods of Development for Assessing Air Pollution Control Benefits, EPA-600/5-79-001.

55. Stephens, R. J., Freeman, and Evans, M. J., "Early Response of Lung to Low Level of Nitrogen Dioxide," Arch. Environ. Health, 3, pp. 311-20, 1972.

56. Larsen, R. I., and Heck, W. W., "An Air Quality Data Analysis System for Interrelating Effects, Standards, and Needed Source Reductions: Part 3. Vegetation Injury," J. Air Pollution Control Assoc., 26, April 1976.

57. Perera, F., and Petito, C., "Formaldehyde: A Question of Cancer Policy?," Science, Vol. 216, June 1982.

58. National Institute for Occupational Safety and Health, U.S. Department of Health and Human Services, "Formaldehyde: Evidence of Carcinogenicity," Current Intelligence Bulletin 34, April 15, 1981.

59. Juhasz, P. C., and Rossano, A. T., Joint Conference Sens. Environ. Pollution, Proceedings 4th, pp. 101-4, American Chemical Society, 1977.

60. Myronuk, D. J., "Augmented Ingestion of CO and SO_x by Occupants of Vehicles while Idling in Drive-up Facilities," Water, Air, Soil Pollution, 7, p. 203, 1977.

61. Cowling, E. B., "Acid Precipitation in Historical Perspective," Environ. Sci,. and Technol., 16, p. 2, 1982.

62. Systems Applications Inc., Preliminary Review of Cost-Effectiveness Considerations for South Coast Air Basin, Nitrogen Dioxide Control Strategies, Publication No. 82179, July 1982.

63. McRae, G. J. and Russell, A. G., Dry Deposition of Nitrogen - Containing Species, paper presented at American Chemical Society, 183rd Annual Meeting, Las Vegas, Nevada, March 28 - April 2, 1982.

CHAPTER SEVEN

CHEMICAL METHANOL PRODUCTION AND USE

A. INTRODUCTION

Methanol, one of the major organic chemicals, can be derived from almost any carbon source. In the past, natural methanol was extracted from wood, and synthetic methanol was made from coal and later from oil; today most of U.S. methanol production is based on natural gas.

The largest current use of methanol is in the production of formaldehyde which, in turn, is being used in the production of plywood and particle board for housing construction. Other end uses of methanol include acrylic sheet production, polyester fibers, and acetic acid-based products. Current U.S. methanol capacity is around 1.3 billion gallons per year, produced by eleven companies.

Current production technology is based on reforming of natural gas in a typical plant, producing 1,000 to 2,000 tons of methanol per day. The major components of the production cost are the cost of raw material -- around 60 to 70 percent of cost at current prices -- and the cost of capital, around 20 percent.

B. CONVENTIONAL METHANOL PRODUCTION TECHNOLOGY

At the turn of the last century, methanol was exclusively produced by extracting it from pyroligneous liquor (obtained during the destructive distillation of wood). In 1926, synthetic methanol from Germany entered the U.S. market at two-thirds of the price of natural methanol. The average cost in New York in 1926 was $0.48/gal for natural methanol. Facing this threat, the wood distillers managed to have the tariff increased to $0.18 and to have legislation passed to the effect that only natural gas could be used as denaturant, which guaranteed them a third of the market at that time. In 1926, the production of synthetic methanol began in the U.S., and production has grown steadily since. Increasing production capacity and competition eventually brought the price down to around $0.30 per gallon, and then stabilized. Early plants were designed in conjunction with other plants to make use of carbon-dioxide or hydrogen by-products.

Interestingly enough, synthesis gas was originally made from coal. A major process for the gasification of coal is the Winkler process, discovered in Germany in 1922. Later, however, the feedstock was shifted to oil and then to natural gas as large petroleum discoveries were made and the cost of these carbon sources dropped. Natural gas was particularly appealing because of its low-sulfur content and federally regulated low prices. By the 1960s, synthetic methanol in the U.S. was almost entirely manufactured from natural gas by a high-pressure process similar to that of ammonia.

In this process, pressurized synthesis gas is usually made by the reforming of natural gas and consists of a mixture of carbon monoxide, carbon dixoide, and hydrogen. Since natural gas contains more than the ideal amount

of hydrogen, carbon dixoide is usually added to balance the excess hydrogen. As a result, methanol producers usually located their plants close to ammonia plants, since large amounts of carbon dioxide are removed from the synthesis gases used to produce ammonia. In a typical process, the above mentioned synthesis gas is desulfurized, cooled, compressed, mixed with recycled gas, and passed to the methanol converter. Zinc chromium oxide catalysts are used in the conversion of synthesis gas to methanol. The methanol-containing gases formed are cooled, condensed, and purified.

In 1967, Imperical Chemical Industries introduced a low pressure synthesis process, based on their newly developed copper-based catalysts, which are much more reactive than the zinc-chromium-based catalysts. The lower pressures and temperatures this allows lower the cost of production substantially. The price of methanol, in fact, dropped from $0.23/gal in 1971 to around $0.10/gal in 1972-1973 (see Table 7-1).

Another available technology is the partial oxidation of heavy feedstocks such as fuel oil. The main advantages of this process are a higher on-stream factor, lower catalyst requirements, but especially feedstock

Table 7-1. HISTORICAL U.S. METHANOL PRODUCTION AND PRICES

YEAR	ANNUAL PRODUCTION (10^6 gals)	PRICE* (¢ per gallon)
1965	432	27
1967	517	26.7
1968	575	25
1969	633	25.4
1970	743	26.7
1971	755	22.8
1972	897	10.7
1973	1064	12.5
1974	1036	20.9
1975	780	39
1976	940	39
1977	973	39
1978	1006	43.1
1979	1100	44
1980	1070	62
1981	1260	75
1982**	1260	70-75

*Wholesale Price in current year dollars
**First quarter

SOURCE: Chemical & Engineering News 1/22/79, 1/28/80, 1/26/82, 3/29/82. Predicasts Inc.'s basebook U.S. Department of Commerce. DRI

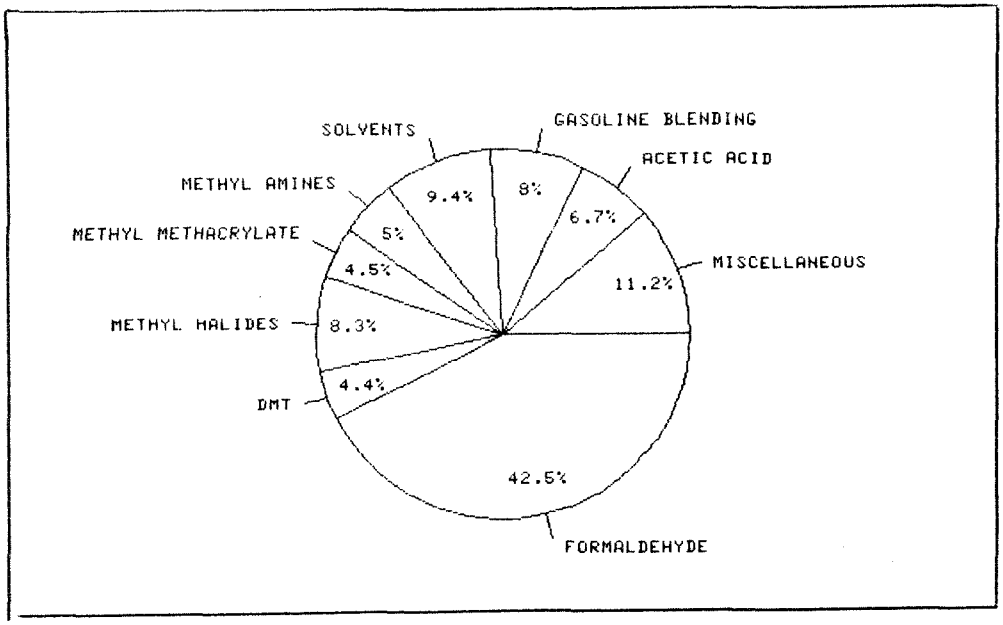
flexibility. In fact, the new plant being built by DuPont at Deer Park, Texas will be based on synthesis gas from petroleum residuum feeds. The disadvantages of the partial oxidation method are that the capital cost of the plant is 70 percent higher than that of the equivalent steam reforming plant (Chem Systems, Inc., 1976), because an air separation plant is usually required to supply oxygen.

C. PAST AND PRESENT TRENDS IN THE METHANOL MARKET

Since 1965 synthetic methanol production grew at an average annual rate of around 7.4 percent. In 1981, 1,260 million gallons of methanol were produced in the U.S. from a capacity of 1,770 million gallons (Ref. 8). A significant portion of the methanol that is produced is consumed by the producers themselves as an input in the production of other chemicals. Table 7-1 prresents a time series of synthetic methanol production and price figures from 1965 to the present.

D. CURRENT METHANOL DEMAND

The main current use of methanol is a feedstock for the production of resins, glues, and plastics. Figure 7-1 shows the major uses of methanol in 1979.



SOURCE: Chemical Engineering, July 1980 (Ref. 7).

Figure 7-1. U.S. METHANOL DEMAND, 1979

The largest single use of formaldehyde is in the production of resins. In a typical year, ureau formaldehyde resins take about 25 percent of formaldehyde output and phenol formaldehyde resins nearly as much. Housing is the biggest single user of those materials. Consequently, methanol production depends very strongly on the cyclical movements in the housing market. It should be noted that, in general, modernization and expansion of existing houses takes a higher proportion of plywood and particle board than does new construction. Therefore, when fewer new houses are built and instead there is more modernization and expansion, methanol demand will continue to be strong. The demand for formaldehyde in mobile homes and other semipermanent living quarters is not counted in housing starts. These uses might show a moderately strong demand for plywood and particle board if demand in a recession shifts toward these lower cost living quarters.

Methanol used for the production of formaldehyde constituted 30 percent of methanol production in 1981. This percentage has dropped from 41 percent in 1980. This may be due to the fact that the housing market, which uses products from formaldehyde, has declined.

The second largest chemical derivative market for methanol is methyl methacrylate (MMA). The largest end use of this chemical is acrylic sheet production; other end uses are surface-coating resins and molding and extrusion powders. Dimethyl terephthalate (DMT) is used in the manufacture of polyester fibers. Except for minor quantities used in the preparation of herbicides and resins for adhesives, printing inks and specialty coatings, the remainder is used to make polyster films and thermoplastic polyester engineering plastics. The other major current use of methanol is acetic acid. The largest end uses for acetic acid are vinyl acetate monomer, which accounted for 44 percent of acetic acid consumption in 1978 and acetic anhydride, which accounted for 28 percent. In 1978, about 17 percent of acetic acid supply was based on methanol, a percentage which, as will be argued below, is expected to grow substantially.

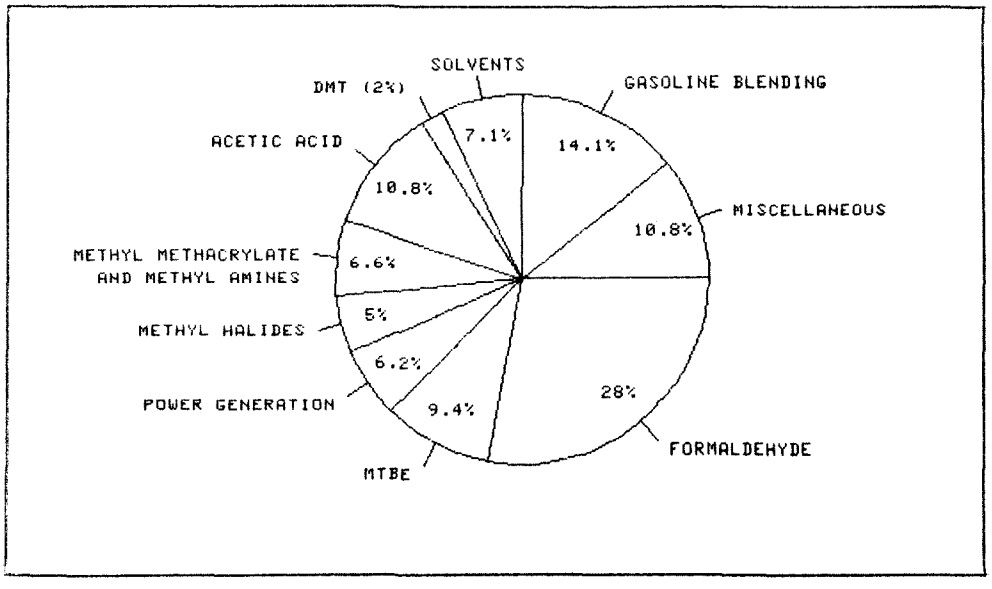
During the 1979-82 period, exports averaged 70 million gallons and imports were approximately 40 million gallons per year.

E. PROJECTIONS OF FUTURE METHANOL DEMAND

DuPont Company of the U.S. predicts a 9 percent per year average increase in methanol demand over the next several years (Ref. 2). Data Resources Incorporated (DRI) projects 1.5 billion gallons of methanol in 1985, and 1.8 billion gallons in 1990, an average annual rate of growth of 3.7 percent. In Figure 7-2, formaldehyde percentage of the total 1990 methanol market is projected to be 28 percent, while that going into gasoline blending is 14.1 percent. The total production of methanol in that year is estimated to be 8.1 million metric tons.

F. UNITED STATES METHANOL SUPPLY

In 1981, there were eleven companies producing methanol in the U.S. Total methanol capacity amounts to 1770 million gallons per year. Methanol



SOURCE: Chemical Engineering, July 1980 (Ref. 7).

Figure 7-2. U.S. METHANOL DEMAND, 1990

producers and their annual capacity and market share are listed in Table 7-2. As one can see, by the end of this year, around 70 percent of methanol capacity will be concentrated in the hands of the three largest producers: DuPont, Celanese, and Borden, Inc.

G. WORLD METHANOL SUPPLY

World methanol production currently stands at 3.52 billion gallons and production level is expected to reach 5.98 billion gallons in 1987 (Table 7-3). This is an annual rate of growth of 11.2 percent. Forecasters disagree on methanol supply/demand. Chem Systems, Inc., (New York) predicts a worldwide shortage by 1990, while British Sulphur Corp (London) observes there would be a glut by 1985 (15). Table 7-4 presents the world methanol production capacity (not including the United States) through 1987.

Table 7-2. U.S. METHANOL PRODUCTION CAPACITY
(Million Gallons/Year)
(Ref. 1,2,3,4)

PRODUCER	1980	1981	1982	1983	1984	1985	1986	1987	1988
AIR PRODUCTS Pensacola, LA	50	50	60	60	60	60	60	60	60
ALLEMANIA CHEM. Plaquemine, LA	100	130	130	130	130	130	130	130	130
ARCO CHEM. Gulf Coast	---	---	---	200	200	200	200	200	200
BORDEN, INC. Geisman, LA	160	180	180	180	180	180	180	180	180
CELANESE CORP Bishop, TX Clear Lake, TX	375	385	385	385	385	385	385	385	385
DUPONT Beaumont, TX Dear Park, TX	340	450	450	450	450	450	450	450	450
EASTMAN CHEM.	---	---	---	---	50	50	50	50	50
GEORGIA PACIFIC Plaquemine, LA	120	125	125	125	125	125	125	125	125
GETTY OIL	---	---	---	100	100	100	100	100	100
MONSANTO Texas City, TX	100	100	100	100	100	100	100	100	100
TENNECO, INC. Houston, TX	80	82	130	130	130	130	130	130	130
Total U.S.	1,325	1,502	1,560	1,860	1,910	1,910	1,910	1,910	1,910
Other Free World	2,280	2,280	2,740	2,885	3,545	4,415	5,085	5,415	5,585
TOTAL	3,605	3,782	4,300	4,745	5,455	6,325	6,995	7,325	7,495

SOURCES: Conoco "The Production, Economics, and Marketing of Methanol," presentation to General Motors Corp., March 1982; Stanford, Connecticut, "Energy Modeling Forecast, "EMF Report No. 6, Feb. 1982.

Table 7-3. FREE WORLD METHANOL BALANCE 1981-1987 (million/gallons/year)

	1981	1982	1983	1984	1985	1986	1987
Existing Production	3.11	3.11	3.22	3.22	3.22	3.22	3.22
Published New Capacity (cumulative) including Gasoline	-	0.3	0.7	1.2	1.86	2.43	2.756
Effective Production	3.22	3.52	3.92	4.42	5.08	5.64	5.98
Comecon Imports	.03	.07	.13	.01	.17	.17	.17
Production & Imports	3.25	3.59	4.02	4.55	5.25	5.71	6.15
Consumption	2.91	3.47	3.74	3.97	4.17	4.3	4.47
Balance	0.34	0.12	0.28	0.58	1.08	1.51	1.68

LIST OF NEW CAPACITY

YEAR	COUNTRY	COMPANY	CAPACITY (10^3gpy)	CUMULATIVE CAPACITY (10^6 gpy)	CUMULATIVE PRODUCTION[a] (10^6 g)
1982	CANADA	ALBERTA	130		
		OCELOT	130	0.5	(.3)
		CELANESE	200		
1983	USA	ARCO	190		
		GETTY	100		
	TAIWAN	CPDC	35	0.9	(.4).7
	TRINIDAD	NEC	110		
1984	SARABIA	SABIC/JAPAN	220		
	LIBYA	NMC	110		
	N. ZEALAND	PETRALGAS	130	1.6	(.5)1.2
	INDONESIA	PERTAMINA	200		
1985	UK	ICI	270		
	SARABIA	SABIC/CELANESE	220		
	MEXICO	PEMEX	270	2.5	(.7)1.9
	BAHRAIN	GPIC	110		
1986	MALAYSIA	PETRONAS	110		
	MALAYSIA	(BORDEN)	110		
	HOLLAND	METHANOR	140		
	ARGENTINA	HUARPES	200	3.1	(.6)2.5
	BANGLADESH	BEXIMCO	110		
1987	GERMANY	SHELL	130	3.5	(.3)2.8
	N. ZEALAND	NZ/MOBIL	200		
1988	USA	TVA	330	4.0	(.5)3.3
	NORWAY	DYNO	170		

SOURCE: Conoco, Stanford, Connecticut.

[a]Cumulative production is less than the capacity would imply because plants being opened during the year and operating at less than full capacity. The numbers in parenthesis are estimates of actual output from the new capacity.

Table 7-4. FOREIGN METHANOL PRODUCTION - NEW CAPACITY
(million/gals/yr)
(Ref. 1,2)

COUNTRY	1980	1981	1982	1983	1984	1985	1986	1987
Argentina							200	
Bahrain						110		
Bangladesh							110	
Canada			400					
China		35						
Germany								130
Indonesia					200		130	
Japan						200		
Libya					110			
Malaysia							220	
Mexico						270		
Netherlands							140	
New Zealand					130			200
Norway								
Saudi Arabia					220			
Taiwan				35				
Trinidad				110				
UK						270		
USSR	100			270				
Yugoslavia			135					
TOTAL	100	35	595	415	660	850	800	330
CUMULATIVE TOTAL	100	135	730	1145	1805	2745	3445	3775

H. REFERENCES

1. Conoco, The Production, Economics, and Marketing of Methanol, presented to General Motors Corp., P. 6, March-April 1982.

2. Carlson, Bruce (DuPont), Methanol Outlook, presented at Chemical Marketing Research Assoc. meeting in New York, p. 127, May 4-6, 1981.

3. Hagler, Bailley & Co., The Emerging U.S. Methanol Industry: Structure, Financing, and Marketing Strategies, exhibit 5.25, Feb. 1982.

4. Goldberg, Terasawa, and Voechs, U.S. Methanol Market: Long-Run Trends and Price Forecasts, JPL unpublished report, October 1979.

5. SRI, Chemical Engineering Handbook.

6. Paul, J. K., Methanol Technology and Applications as Motor Fuels, pp. 82-100, 1978.

7. Weismantel, Guy E., "Methanol Supplies: Too Much or Too Little?" Chemical Engineering, July 14, 1980.

8. Chemical Engineering News: 01/22/79, 01/28/80, 01/26/81, 03/29/82: Predicasts Inc.'s Basebook; Bureau of Labor Statistics, U.S. Dept. of Commerce.

CHAPTER EIGHT

METHANOL UTILIZATION IN VEHICLES

The dominating potential use for methanol is as a fuel for the millions of automobiles and trucks which will be on the road in the year 2000. Between the present time and the year 2000, transitional markets may develop which can enable successful introduction of both methanol fuel and methanol automobiles into the private marketplace. Therefore, in addition to the examination of neat methanol as a fuel for private automobiles, several other transportation submarkets have been examined. These markets include: methanol as an octane-blending agent for gasoline; the medium- and heavy-duty truck and bus market; and the near-term light-duty commercial and public fleet vehicle market. The following paragraphs present a short description of the contents of Chapter 8.

Methanol use for gasoline blending is examined in Section A from the perspective of both methanol and a co-solvent as a direct blending agent, and methanol as a feedstock to MTBE production. The technical issues of methanol blending use in automobiles are reviewed. These issues include: driveability, emissions, material compatibility and corrosion. The economic potential for methanol blends is examined through use of a simple parametric octane number barrel cost model, and a co-solvent limited demand curve is estimated.

Section B presents an examination of the potential for neat methanol fuel in private passenger vehicles. In a manner similar to methanol and gasoline blends, the technical aspects of neat methanol fuel as used in vehicles are reviewed. The economic viability of methanol fuel for private passenger vehicles is examined from the perspective of a changing gasoline vehicle baseline challenged by an improving methanol vehicle technology. The implications of dissociated methanol technology are also examined.

Engine and tailpipe emissions are separately discussed in each of the subsections of Chapter 8. In addition, an overview of methanol engine emissions is presented in Section C. The implications of the emissions from methanol vehicles on urban air quality have been presented in Chapter 6.

Medium- and heavy-duty applications, such as trucks and buses, are examined in Section D. Three representative technologies, the Texaco TCCS engine, the Mercedes-Benz fully vaporized methanol engine, and the M.A.N. direct-injected stratified charge engine are discussed in more detail. The potential economic viability of methanol fuel versus diesel fuel is presented from the perspective of three possible petroleum price scenarios.

One often mentioned near-term market is light-duty commercial and public fleet vehicles. Section E examines this potential market and provides rough estimates of the market potential and the implications on near-term methanol fuel sales.

A. METHANOL GASOLINE BLENDS

A potentially significant demand for methanol is as an octane-enhancing blending agent for unleaded gasoline. Currently, methanol is used directly in gasoline or as a feedstock for MTBE in Europe and in the U. S. Petroleum Allocation District III -- Gulf States PAD III. A five percent blend of methanol in the unleaded gasoline pool could increase West Coast methanol demand by 4,000 ton per day.

The use of methanol by the refinery or blending sectors within California could impact transitions to broader use of methanol fuel due to three factors:

(1) Methanol use in gasoline blending may provide an elastic buffer for supply discontinuities resulting from large methanol production facilities coming on-stream.

(2) Significant use of methanol in gasoline blending would encourage the development of bulk-handling and transport facilities for methanol in areas adjacent to ports and refineries.

(3) Blending use would establish methanol as a standard product within the California energy industry.

Methanol (as well as other alcohols) can be blended with gasoline in various proportions or used as a neat fuel in spark-ignited engines. Blending is best and most easily done at the refinery using the appropriate additives and petroleum fractions. In principle, any combination of alcohol and gasoline could be delivered to the vehicle fuel tank using a variable blending pump at the retail service station; however, fuel vapor pressure control limits this approach. Fuel blending can also be accomplished onboard the vehicle by use of a dual fuel tank system.

It is also known that methanol cannot be blended in any proportion greater than about 10 percent without making appropriate modifications to present cars. Some material incompatibility problems may appear with even lower concentration blends in cars not designed for alcohols. The amount of methanol that could be added to the fuel tank as a blend with gasoline, ignoring such problems as phase separation, vapor lock and corrosion, would be limited largely by decreased driveability due to the leaning of the carbureted air/fuel mixture.

1. Methanol/Gasoline Blends in Vehicles

The use of methanol as a blending component provides an opportunity for the early introduction of the fuel into the transportation market and may contribute to demand sufficienty to justify initial remote natural gas-based production of methanol. Use of methanol as a blending agent both increases octane number and displaces petroleum. While there may be economic and transitional reasons for blending methanol into gasoline, several technical problems are associated with the use of blends in automobiles.

The performance of vehicles using methanol/gasoline blends is discussed in the following material. The performance factors considered include driveability, material compatability, fuel consumption, and emission characteristics.

a. Driveability. Fuel volatility, lean combustion, and phase separation can directly affect the drivability of a vehicle fueled with a methanol blend.

Fuel Volatility. Methanol has a definite effect on the volatility of methanol/gasoline blends. Methanol is a polar liquid and gasoline is nonpolar. The use of small amounts of polar methanol in nonpolar gasoline results in a large increase in fuel vapor pressure. The effect of methanol on the Reid Vapor Pressure (RVP) of the blend is shown in Figure 8-1 (Ref. 1). The addition of only 2 percent methanol increases the RVP 3 psi, even though the volatility of pure methanol is less than that of the base gasoline. Excessive vapor pressure can produce vapor lock problems (engine stalling), hesitation and poor vehicle acceleration. The use of higher alcohols as co-solvents in gasoline/methanol blends tends to reduce the vapor-pressure increase due to the higher molecular weights.

The vapor-locking tendency of a fuel is related to its front-end volatility, or fraction distilled below about 158°F and RVP. The addition of methanol increases the vapor-lock tendency of gasoline. Increased front-end volatility also tends to increase evaporative emissions. Methanol has a significant effect on the distillation characteristics of the blend. Figure 8-2 (Ref. 2) presents a distillation curve for a typical gasoline fuel before and after the addition of various concentrations of methanol. The blends vaporize more rapidly at temperatures less than the 149°F boiling point of methanol. At higher temperatures, approaching 200°F, the difference in vaporization between gasoline and blends containing about 15 percent (or less) methanol becomes much less pronounced.

Such volatility characteristics are typical of blends obtained by the addition of methanol to finished gasoline after the normal refinery process. Blends initially produced at the refinery can be adjusted for front-end volatility by decreasing some fraction of the lighter hydrocarbons, such as butane and pentane. The displacement of low-cost butane with methanol could produce a higher cost alternative fuel. A substitution of the lighter hydrocarbons could also create a surplus of butanes in the marketplace. However, the value of methanol for increasing the octane number of the blend may more than compensate.

In addition to vapor lock-free operation, good driveability includes quick starting, stall-free engine warm-up and reliable engine-idle conditions. Several investigations have found that warm-up driveability for methanol gasoline blend is not as good as gasoline. Increasing methanol concentration decreases the warm-up drivability. Fuel injection cars appear to be affected less than carbureted cars. The warm-up driveability effects of blends apparently result from the high heat of vaporization of methanol. This contributes to the incomplete vaporization of the fuel in the engine intake

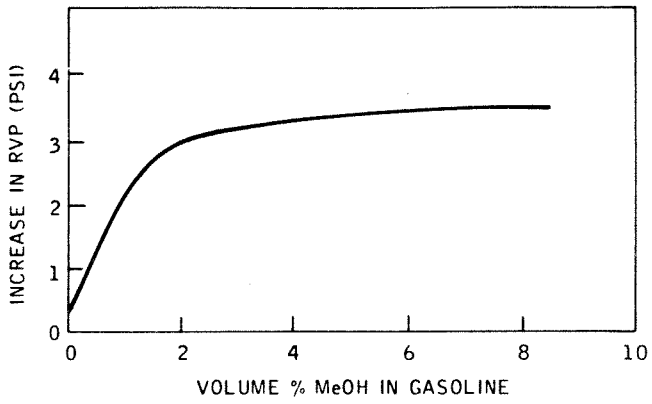


Figure 8-1. EFFECT OF METHANOL ON GASOLINE VAPOR PRESSURE (Ref. 1).

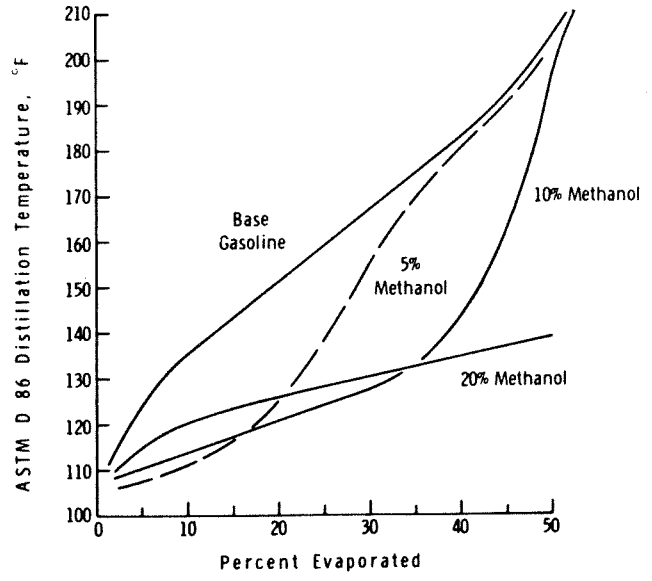


Figure 8-2. EFFECT OF METHANOL ON FRONT-END VOLATILITY (Ref. 2).

system, causing poor cylinder-to-cylinder distribution. Once the vehicle has been warmed up, driveability due to poor volatility does not appear to be a problem with blends.

Lean Combustion. Because of the methanol stoichiometry, substitution of a methanol blend for gasoline without adjustment of the carburetor results in a leaner air/fuel mixture. This additional "leaning" can have a pronounced effect upon driveability, particularly with newer automobiles which are already factory calibrated to be operated lean or stoichiometric. Present environmental regulations prohibit carburetor adjustments. Although such adjustments could improve driveability using blends, an "over-rich" condition would result if the vehicle were operated on straight gasoline. However, recently commercialized feedback controlled carburetor and fuel injection systems should be able to compensate to some degree for the leaning effect of methanol.

If lean operation impairs driveability, it is due to the susceptibility to misfiring in the leanest cylinders. In addition, the leaning effect with blends may be aggravated by preferential evaporation of the low-boiling methanol. Hence the vapors entering certain engine cylinders are leaner than the average mixture.

Phase Separation. The presence of small amounts of water can cause methanol/gasoline blends to separate into gasoline and water/alcohol phases. The obvious chemical differences between the two separated phases can cause severe driveability problems. The severity of phase separation depends upon the ambient temperature and the solubility of methanol in the base gasoline. Methanol is least soluble in paraffins and napthenes and more soluble in aromatics and olefins. At lower temperatures, the solubility of methanol in gasoline is decreased. The solubility can be increased, however, by the addition of higher alcohols which act as co-solvents and, also, tend to solubilize small quantities of water in the blend. Additives found effective in methanol/gasoline blends (at relatively high concentrations) are the branched alcohols such as isopropanol and tertiary butyl alcohol. The problem of using solubilizing additives is basically economic. Existing commercial methanol blends use higher alcohols to control phase separation. Separation can still occur if there is sufficient water present and/or the temperature is low, even with co-solvents in the blend.

Water is usually present in gasoline storage tanks. It can enter the storage and transport system from rain sources, other pipeline products, marine operations or absorbtion from the air. If phase separation occurred within the distribution system, methanol would be lost from the blend and the operation of distribution facilities disrupted. In addition, the separated aqueous phase would be difficult to dispose of, and corrosion of some equipment would probably be accelerated. Therefore, transport and storage operators must know that the gasoline contains methanol and the de-watering/cleaning procedure for the systems must be followed. Frequent batching of methanol blends through the system would tend to remove any water in the system. Therefore, if methanol blends were in common use, the water absorbtion problem would be minimal.

Blending Octane Number. The high octane quality of methanol makes it an attractive blending component for gasoline. As measured by the ASTM Research octane method, methanol has been reported to rate between 106 to 115 octane numbers (ON). The ASTM Motor method for measuring octane numbers yields ONs in the range of 88 to 92. The difference between the Research and Motor octane ratings is defined as the fuel "sensitivity". The road anti-knock quality of a commercial grade fuel measured in actual driving depends upon both of the laboratory measurable ON ratings.

The use of methanol as a high ON blending component increases the blended fuel's sensitivity. The tendency for road knock may be higher than the ON indicates, depending upon the hydrocarbon composition of the base gasoline. Methanol blends, because of their higher sensitivity, might need to be marketed with a higher octane number than that required of gasoline to achieve the same road anti-knock performance to give equivalent car performance.

b. Material Compatibility. The long-term compatibility of methanol with existing automotive fuel system components is not adequately known by automobile manufacturers. The present systems have been developed to be corrosion-resistant and otherwise compatible with petroleum distillates. To a great extent, the material compatibility problems are concentration dependent: 4.5 percent methanol causes little or no problems as documented in a recent EPA waiver application, whereas 10 to 15 percent blends have shown severe problems.

Metal Corrosion. There is limited evidence of the corrosivity of methanol in blends (or as a neat fuel) to metals presently used in most vehicle fuel systems. Metals known to have sustained corrosion damage include copper, zinc, aluminum, steel and magnesium (Ref. 3). Terne metal coatings, an alloy of tin and lead commonly used inside gas tanks, suffer rapid deterioration upon contact with methanol.

The severity of the corrosion problem is influenced to a large degree by the amount of water in the fuel. The separated aqueous phase of a methanol/gasoline blend has been observed to be especially corrosive. Work is in progress to develop special inhibitors to minimize the corrosive behavior of methanol. Corrosion and compatibility problems are also influenced by temperature, fuel and other factors, and thus have not been universally observed by all investigators.

Compatibility With Other Materials. In addition to corrosion of metals, methanol can be incompatible with many non-metallic fuel system materials. The solvent characteristics of methanol have caused swelling of Viton parts in carburetors, hardening and cracking of buna-N coated fuel pump diaphragms, stiffening of neoprene-coated diaphragms, shrinking of cork gaskets, disintegration of polyurethane, hardening of vinyl fuel hoses, and softening of polyester-laminated fiberglass (Ref. 4). These problems are reported to be more severe with neat methanol as compared with blends, and can be avoided by selecting suitable materials for fuel systems.

Lubricant Compatibility. The long-term compatibility of methanol with existing automotive lubricants has not been established. Some reports of increased ring and cylinder wear may be due to: (1) the removal of the cylinder wall oil film by the alcohol and (2) the prolonged engine warm-up time. Gasoline fuel under similar conditions causes oil dilution, but unburned methanol is insoluble in most oils. Some detergent additives have shown evidence of a separation in the presence of methanol/oil emulsions. Work is currently in progress to develop lube oil additive packages compatible with methanol fuels. Recent California tests indicate that a conservative policy of frequent oil changes minimizes lubricity problems.

c. Fuel Consumption. Due to the lower energy content of methanol (56,000 vs 115,400 Btu/gal for gasoline), a blended fuel could be expected to yield higher fuel consumption on a miles per gallon (MPG) basis. To a first approximation, the volumetric fuel consumption of any fuel (at a given equivalence ratio) is proportional to the fuel energy content. The equivalence ratio is defined as the actual fuel-air ratio divided by the stoichiometric fuel-air ratio required for complete combustion. However, the potential for improved engine thermal efficiency due to lean combustion, reduced flame temperatures, together with the increased ON of methanol which may permit higher compression ratios, makes the prediction of fuel consumption using blends uncertain.

The addition of methanol to gasoline reduces the fuel energy content and, if carburetion is not adjusted for the change, results in a leaner air/fuel mixture supplied to the engine. Feedback/oxygen sensor carburetion or fuel injection should automatically adjust for this if the change is not too great. In older cars with relatively rich carburetion, the leaning effect of a blend may improve thermal efficiency and compensate for the loss in energy content, so that net increases in fuel economy are possible. However, because some late model cars either run lean or stoichiometric, further leaning by a blend may not help fuel economy. For this situation, volumetric fuel economy could be less with blends because of the lower energy content. As a practical matter, with blends of more than about 10 percent methanol, carburetion should be adjusted in order to maintain exhaust emission control and acceptable driveability. Carburetor adjustments, on the other hand, are not presently allowed under existing environmental regulations.

d. Exhaust Emission. Leaner operation of an engine will tend to reduce carbon monoxide (CO), reduce hydrocarbons (HC), and may increase or decrease oxides of nitrogen (NO_x), depending upon the factory carburetor setting. Substantial decreases in CO emissions have been observed with methanol/gasoline blends, while unburned fuel emissions (including unburned methanol) have been either increased or decreased. Methanol from the exhaust has been determined to exhibit low photochemical reactivity. Uncontrolled nitrogen oxide emissions are high when operating the engine in the lean side near stoichiometric combustion. Therefore, if the vehicle is originally adjusted to operate stoichiometric or slightly lean on gasoline and not modified when a methanol blend is substituted, the leaning effect of the blend may reduce the NO_x emission. If the vehicle originally operated fuel rich, however, this same leaning effect should increase the NO_x emissions.

When methanol blends are used, the possibility of increased emission of formaldehyde in the exhaust exists. Formaldehyde is the lowest molecular weight aldehyde, and a known eye irritant. Aldehydes are photochemically very reactive and could, therefore, contribute significantly to smog formation. Increased aldehyde emissions have been reported by several investigators with methanol blends. In the case of lean mixtures, as normally encountered when methanol blends are used in unmodified vehicles, the formaldehyde might be converted to CO_2 and H_2O by an oxidation catalyst before reaching the tailpipe. A recently completed study (Ref. 4) concluded that the photochemical reactivity of exhaust emissions was unchanged when blends of up to 15 percent methanol were substituted for gasoline.

e. Vehicle Research Tests. Vehicle testing of methanol and other alcohols blended with gasoline has been performed by U.S. DOE at Bartlesville and by contractors such as University of Santa Clara and Southwest Research Institute. Testing has also been performed by the California Energy Commission, and oil companies such as Union Oil under contract to DOE or ARCO in support of its waiver application. The General Motors vehicle research test will be taken as representive of these tests. It will be supplemented by the data from DOE/Bartlesville in the area of emissions and by the Union Oil data in the area of aldehyde emissions. The results of the ARCO tests will be found in a following section on Clean Air Act Section 211(f) waivered fuels.

A comprehensive experimental program was conducted by Brinkman, et al. (Ref. 5), of General Motors. Two different production vehicles were evaluated using several different unleaded gasolines and gasoline blends containing both methanol and ethanol at 10 percent and 25 percent concentrations. Comparative evaluations were made to determine the effect of fuel-type on emissions, fuel economy, driveability, performance, and road octane requirements. Carburetor modifications were made to determine the effect of equivalence ratio on performance.

Emissions. The GM study found that the response of vehicle exhaust emissions to alcohol addition depends upon the original calibration of the fuel induction system. Changes in emissions caused by adding 10 percent alcohol in a vehicle equipped with a stock carburetor are shown in Figure 8-3. The observed effect of reduced emissions can be attributed to leaning of the intake charge (Ref. 6).

Tests by GM were also run using three different carburetors to provide a range of air-fuel ratios not achievable with the production carburetor. The results of these tests are summarized as follows. For cars operating rich on gasoline, the addition of methanol causes a decrease in exhaust hydrocarbons and carbon monoxide and an increase in nitrogen oxides. For cars originally carbureted lean, carbon monoxide emissions were reduced further; hydrocarbons and nitrogen oxides changes were dependent upon the actual level of equivalence ratio operation.

The Bartlesville Research Center of DOE (Ref. 7) has tested the effects of methanol blends on ten 1974 and 1975 automobiles. Four of the vehicles did not have exhaust catalysts. The emissions averaged across the ten vehicles are shown in Table 8-1. These data show HC increasing 4 to 50 percent, NO_x remaining within 10 percent of reference fuel value, and CO decreasing (with the exception of 5 percent methanol at 100°F). However, 1974/1975 federal emissions certified vehicles are not the same as California vehicles of the 1980s; no co-solvent was used, no adjustment was made to the volatility of the gasoline when methanol was added; and the methanol concentrations are higher than methanol blended gasolines customarily sold in the United States.

Aldehyde emissions were specifically examined in the Union Oil study (Ref. 3). The results are summarized in Table 8-2 (see also aldehyde row on Table 8-1). "Modified carburetor" refers to the rejetting required by the leaning effect of the high alcohol content of the test fuels. This table shows that high alcohol concentrations cause significant increases in aldehydes but also shows that the catalyst is effective in removing them.

Table 8-1. AVERAGE EXHAUST EMISSIONS AND ENERGY CONSUMPTION OF TEST VEHICLES A THROUGH J OPERATING ON COMMERCIAL GASOLINE BASE FUEL AND METHANOL BLENDS AT 20°, 75°, AND 100°F AMBIENT TEMPERATURES

	AMBIENT TEMPERATURE, °F								
	20			75			100		
	INDOLENE CLEAR	5% MeOH	10% MeOH	INDOLENE CLEAR	5% MeOH	10% MeOH	INDOLENE CLEAR	5% MeOH	10% MeOH
EMISSIONS (g/mile)									
CO	40.3	35.7	29.2	13.5	10.1	8.2	13.2	18.3	13.2
HC	2.5	2.6	2.8	1.1	1.3	1.5	1.2	1.6	1.8
NO_x	1.9	2.1	2.0	2.1	2.0	1.9	2.0	1.8	1.8
Aldehydes	0.11	0.13	0.16	0.10	0.11	0.12	0.09	0.10	0.12
Methanol	0.01	0.08	0.15	0.02	0.07	0.13	0.02	0.08	0.14
FUEL ECONOMY (miles/10^5Btu)									
EPA CVS cycle	9.3	9.1	8.9	10.0	9.7	9.7	10.4	10.0	10.0
EPA Hwy. cycle	15.8	15.3	14.8	15.9	15.2	14.8	16.0	15.9	15.7

SOURCE: Allsup, J. R., "Experimental Results Using Methanol/Gasoline Blends as Automotive Engine Fuel, Bartlesville Energy Research Center, Report RI-76-15, January 1977.

Table 8-2. EXHAUST ALDEHYDE DETERMINATIONS

CAR AND CARBURETOR	FUEL[b]		ALDEHYDE CONTENT,[a] ppm BY VOLUME			
			BEFORE CATALYST		AFTER CATALYST	
			IDLE	56 km/hr (35 mph)	IDLE	56 km/hr (35 mph)
VOLVO, FUEL INJECTION	CD-3		23	28	1	2
	CD-4		--	--	--	2
	CD-5		27	33	1	2
	CD-6		--	--	--	2
CHEVELE, STANDARD CARBURETOR	CD-3	Run 1	22	10	11	7
		Run 2	25	31	2	8
		Run 3	19[c]	16	13[c]	10
		Avg.	22	19	7	6
	CD-5,	Run 1	41	79	14	11
		Run 2	35[c]	72	30[c]	10
		Avg.	38	76	14	11
CHEVELLE, MODIFIED CARBURETOR	CD-4		32	20	12	2
	CD-5		14	9	10	6
	CD-6	Run 1	--	31	--	21
		Run 2	38	12	2	2
		Run 3	52[c]	20	6[c]	2
		Avg.	45	21	2	7

a Aldehyde content determined by 3-methyl-2-benzothiazolone hydrazone (MBTH) method

b Fuel CD-3 = low RVP base fuel (51 kPa, 7.5 lb); Fuel CD-4 = 15.6 vol % methanol in base fuel; Fuel CD-5 = 18.0 vol % methanol with 25% C_2-C_4 alcohols in base fuel; Fuel CD-6 = 18.1 vol % C_3-C_7 alcohols in base fuel.

c Sample taken after protracted idling (about 15 minutes) for preceding run. After-catalyst value omitted from average because of presumed catalyst cooling.

SOURCE: Keller, Nakaguchi, Ware, Methanol Fuel Modification For Highway Vehicle Use, Final Report for U.S. Department of Energy, July 1978.

Fuel Economy. Fuel economy data were obtained by GM with the stock carburetor at several steady-state road-load points. The volume-based data are shown in Figure 8-4 for the three different fuel types. At low speeds, the results are nearly identical. At higher road speeds, the blended fuels exhibited poorer fuel economy. Figure 8-5 shows the same data plotted on an energy basis. Since the test results did not converge to a single

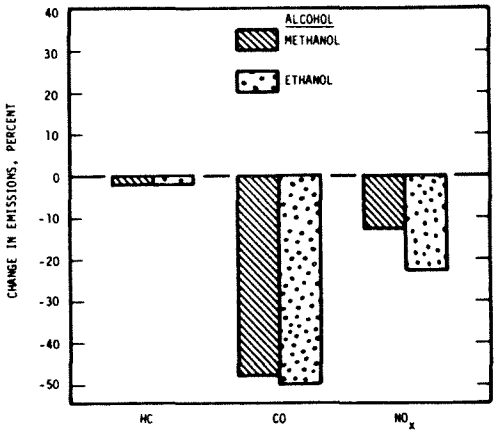


Figure 8-3. CHANGE IN EMISSIONS CAUSED BY ADDING 10 PERCENT ALCOHOL TO GASOLINE (Ref. 6)

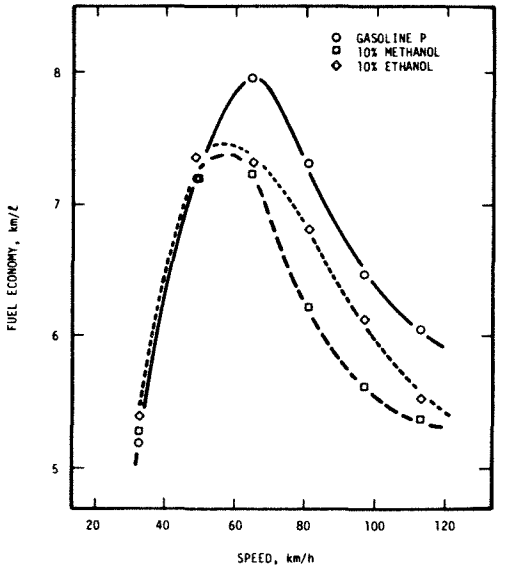


Figure 8-4. CHANGE IN LEVEL-ROAD-LOAD FUEL ECONOMY CAUSED BY ADDING 10 PERCENT ALCOHOL TO GASOLINE, VOLUME BASIC (Ref. 5)

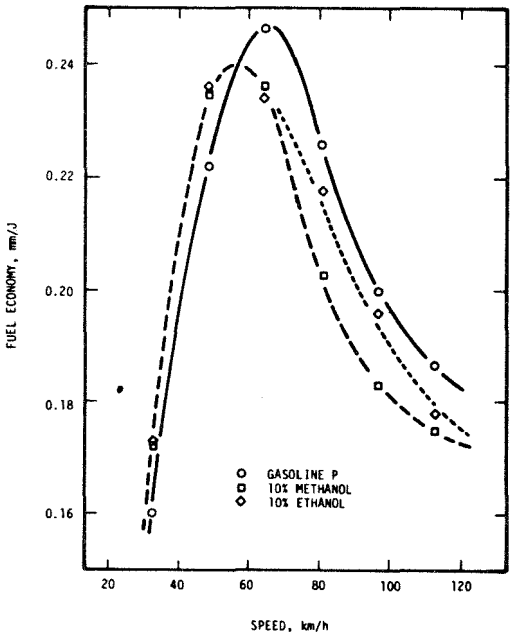


Figure 8-5. CHANGE IN LEVEL-ROAD-LOAD FUEL ECONOMY CAUSED BY ADDING 10 PERCENT ALCOHOL TO GASOLINE, ENERGY BASIC (Ref. 5)

value, the conclusion was made that the results were additionally affected by stoichiometry. The amount of the decrease in the volume-based fuel economy depended upon (in addition to differences in fuel heat value) the leaning of the intake charge. It should be noted that in Figures 8-3, 8-4 and 8-5 the analysis was done with stock carburetors.

Driveability. Subjective driveability tests were conducted on both the road and chassis dynamometer. During these tests, engine starting characteristics were noted. In addition, various malfunctions such as hesitation, stumble, surge, etc., were rated by the driver. The combined ratings were assigned "demerits" which were then adjusted by weighting factors according to the considered importance of the specific deficiency.

The driveability results are shown in Figure 8-6 as a function of operating equivalence ratio. The effect of fuel type upon driveability is seen to be very important at equivalence ratios less than about 0.9. Thus, use of methanol blends in a vehicle factory calibrated for lean operation would cause severe driveability problems.

The effect of ambient temperature on driveability was also evaluated by GM for both the base gasoline and a 10 percent methanol blend. These results

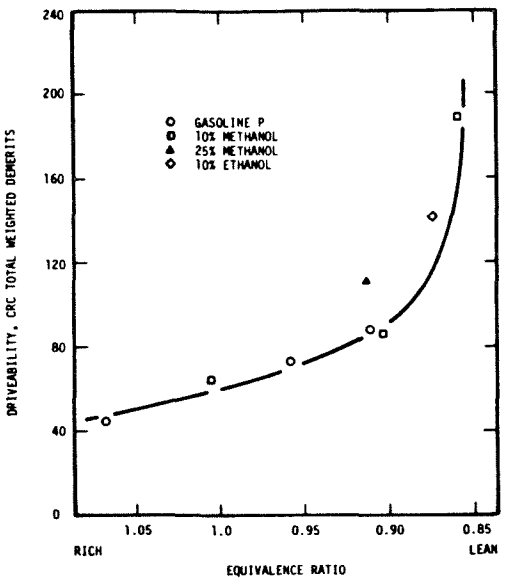


Figure 8-6. EFFECTS OF ALCOHOL AND CARBURETION ON ROAD DRIVEABILITY (Ref. 5)

are given in Figure 8-7. As shown, vehicle driveability suffers with decreasing ambient temperature for both fuels. Because of the leaning effect with methanol, however, driveability deteriorates more rapidly.

Performance. The wide-open-throttle response of the engine varied directly with the operating equivalence ratio irrespective of fuel composition. As noted previously, alcohol addition to gasoline can either improve or deteriorate engine performance depending upon the factory calibration of the carburetor. This is primarily a function of the auto's age, since few if any newer cars are set rich. Consequently, a typical fleet or automobile population must be specified before generalizations regarding the expected performance effects can be made.

Octane Number. The effect of the Research and Motor ONs on the road antiknock quality is shown in Figure 8-8 for a range of methanol blends. Although a definite trend was indicated for various engine speeds, the data show that the road octane ratings of blends could probably not be predicted on the basis of the two standard ASTM methods if the mixture ratios were not recalibrated for methanol blends.

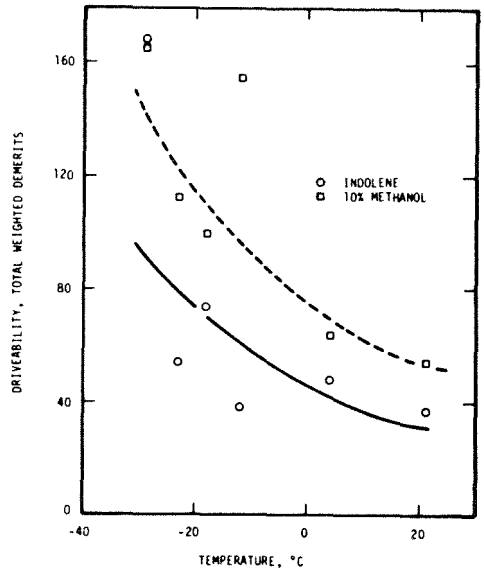


Figure 8-7. EFFECTS OF TEMPERATURE AND METHANOL ON DRIVEABILITY ON CHASSIS DYNAMOMETER, CAR Z (Ref. 5)

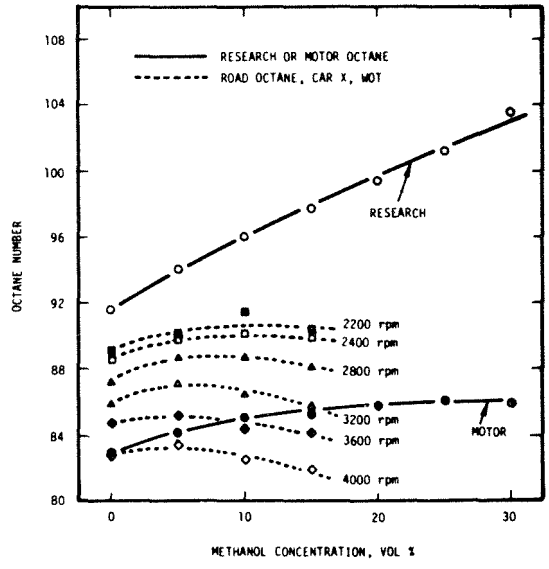


Figure 8-8. EFFECT OF ADDING METHANOL TO GASOLINE ON RESEARCH, MOTOR, AND ROAD OCTANE NUMBERS (Ref. 5)

f. EPA Waiver-Approved Methanol Gasoline Blends. Section 211(F) of the Clean Air Act requires that fuels used in an emission-certified vehicle be substantially similar to fuels in use in 1974. A waiver must be granted before a fuel which does not need this condition can be entered into commerce. Fuels containing more than a very small amount of methanol do not meet this condition. Therefore, before they can be used in vehicles, methanol gasoline blends must be granted a waiver by EPA. Several waivers have been submitted and approved for methanol-containing gasoline blends including: Sun Oil for a 2.75 percent TBA, 2.75 percent methanol; Anafuels (now American Methyl) for a blend of methanol, higher alcohols, and a proprietary corrosion inhibitor; and ARCO for 3.5 percent by weight oxygen and at least a one-to-one ratio of tertiary butyl alcohol to methanol. (This permits among other combinations 4.75 percent methanol and 4.75 percent TBA.) Additionally, a waiver application has been submitted by DuPont for 3 percent methanol without a co-solvent.

Rather than review the data contained in all the various waiver applications, only the data contained in the most recent ARCO waiver will be reviewed. The data contained in the waiver application is quite extensive and, for the most part, parametric in the amounts of both methanol and TBA. In regard to the other waivers and waiver applications, the Sun Oil waiver has been essentially subsumed by the ARCO waiver; the DuPont waiver application has yet to be approved by EPA and may be subject to amendments or modifications; and the Anafuel's blend still has independent vehicle testing pending. Exhaust emissions, evaporating emissions, and driveability data and test results on methanol TBA blends will be briefly reviewed and abstracted from the waiver application.

Eleven test vehicles were tested by ARCO using the 1978 federal test procedures for exhaust emissions with a back-to-back testing of the test fuels and a base fuel. The results of a paired difference test for the exhaust emissions comparisons are presented in Table 8-3.

Table 8-3. PAIRED DIFFERENCE TEST - ALL VEHICLES COMBINED

FUEL	EMISSIONS	90% CONFIDENCE INTERVAL	INTERPRETATION
5V% MeOH/5V% GTBA	HC	-0.14 to -0.36	HC decreases
	CO	-3.33 to -12.31	CO decreases
	NO_x	0.04 to -0.32	NO_x unchanged
16V% GTBA	HC	-0.11 to -0.37	HC decreases
	CO	-3.60 to -12.12	CO decreases
	NO_x	-0.03 to -0.33	NO_x decreases
Gasohol	HC	-0.14 to -0.42	HC decreases
	CO	-4.31 to -12.93	CO decreases
	NO_x	0.05 to -0.21	NO_x unchanged

SOURCE: Atlantic Richfield Company, Clean Air Act Section 211(f) Waiver Application (April 17, 1981).

The figures in the third column represent the 90 percent confidence level for the difference between base and test fuel measured in grams per mile, and determined by standard statistical techniques.

By testing vehicles with oxyginated fuels that cover a range of oxygen contents, the parametric changes in tailpipe emissions versus oxygen content for an oxidation catalyzed vehicle were estimated. These results are presented in Figure 8-9.

As can be seen from this figure, as the oxygen content of the fuel increases, the tailpipe emissions of carbon monoxide and hydrocarbons decrease, whereas the levels of NO_x increase slightly.

For fuels containing only hydrocarbons without oxyginates, the total evaporative emission is strongly correlated to the front-end volatility index of the fuel. Figure 8-10 shows an example of this relationship, originally taken from California Air Resources Board data. The important implication of this relationship is that vehicle evaporative emissions can be regulated by regulating the front-end volatility index of the fuel. (It should be noted that fuel volatility is not the only means that is used to control vehicle evaporative emissions.) To support its waiver application, ARCO demonstrated that such a relationship also holds for fuels containing oxyginates. Figure 8-11 shows the similar relationship to the above for fuels containing oxyginates. The oxyginated fuels contain 4.5 percent methanol by volume and 4.5 percent GTBA by volume. Based upon these and other data presented in the application, ARCO concluded that... "extending the finished fuel oxygen limit to 3.5 percent by weight... will not result in emission standards violations as long as volatility limits are maintained." In the approval of the waiver application, the Administrator of EPA concluded that ... "the subject additive will not cause or contribute to the failure of vehicles to meet evaporative emission standards provided the final fuel is blended to meet the ASTM volatility specifications appropriate for the area and time of year as provided in this waiver."

The driveability of vehicles using methanol-TBA blends was tested by several means. In one set of tests, driveability (measured by standard CRC procedures) was measured for several vehicles and several different temperatures parametric in the volumetric concentration of methanol and TBA. Figures 8-12 and 8-13 show the results of such tests with a 1974 California Pinto. As can be seen from the figures, that although total weighted demerits did increase as the concentration of the alcohols increased, driveability remained in the good range with the exception of low volatility fuel and cool temperatures. (Such tests are strongly dependent upon the vehicle, and other vehicles tested by ARCO yielded different driveability results.) In another test of driveability, 150 cars owned and driven by employees of the ARCO Petroleum Products Harvey Technical Center were used to compare the driveability of conventional gasoline, a gasoline blend containing 4.5 percent methanol and 4.5 percent GTBA, and commercially available gasohol. The results of the comparisons between the three fuels are presented in Table 8-4.

The only area in which the driveability of the methanol blend was noticeably worse than the base gasoline fuel was in cold engine performance. It was argued in the waiver application that the cold engine performance of the methanol blend was equivalent to that of gasohol and, further, that gasohol was a consumer-acceptable fuel.

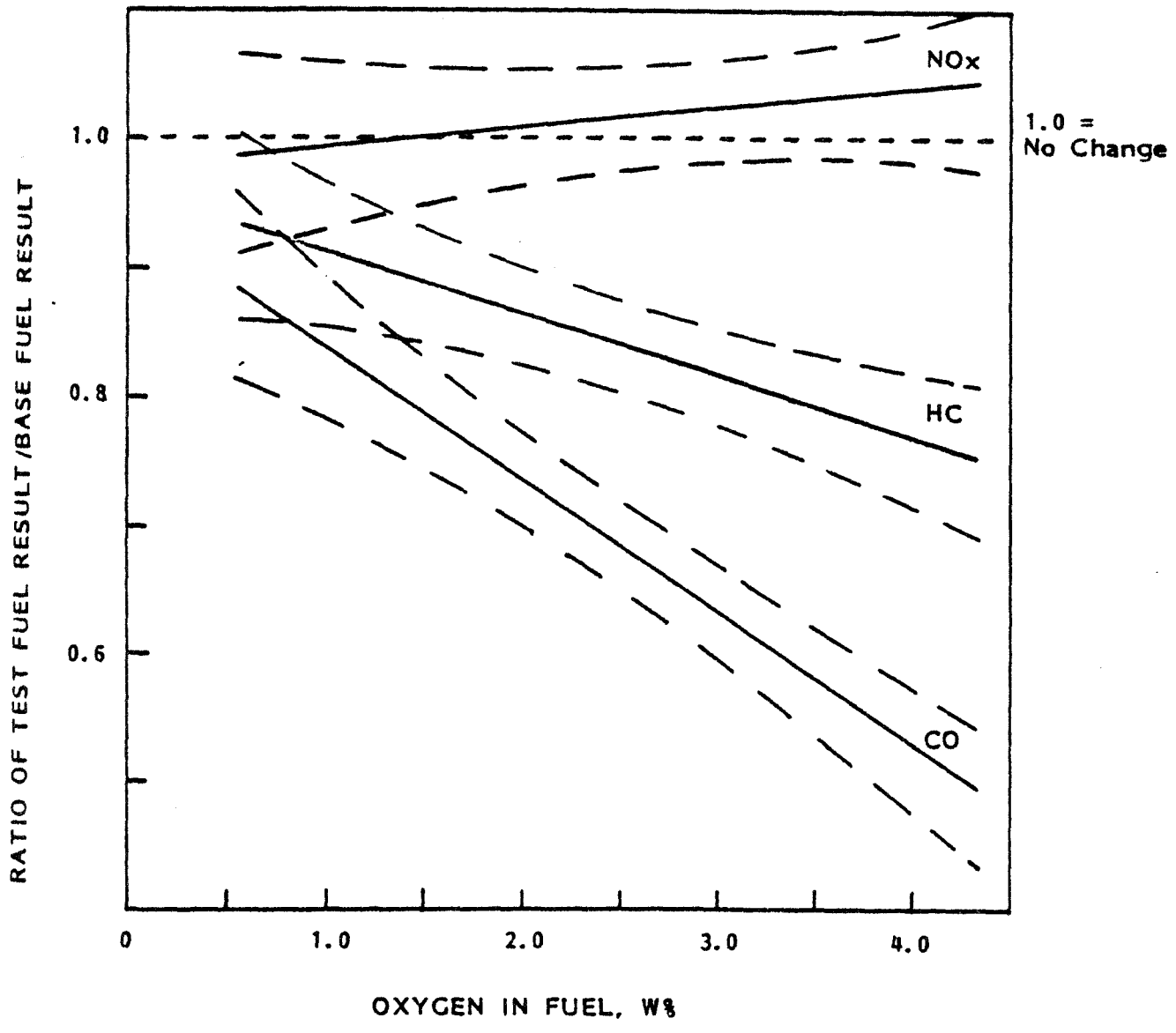


Figure 8-9. EFFECT OF OXYGEN CONTENT OF FUEL ON EXHAUST EMISSIONS OF OXIDATION CATALYST VEHICLES* (Source: ARCO Ref. 16)

*Illustrated by regression lines and 95% confidence intervals.

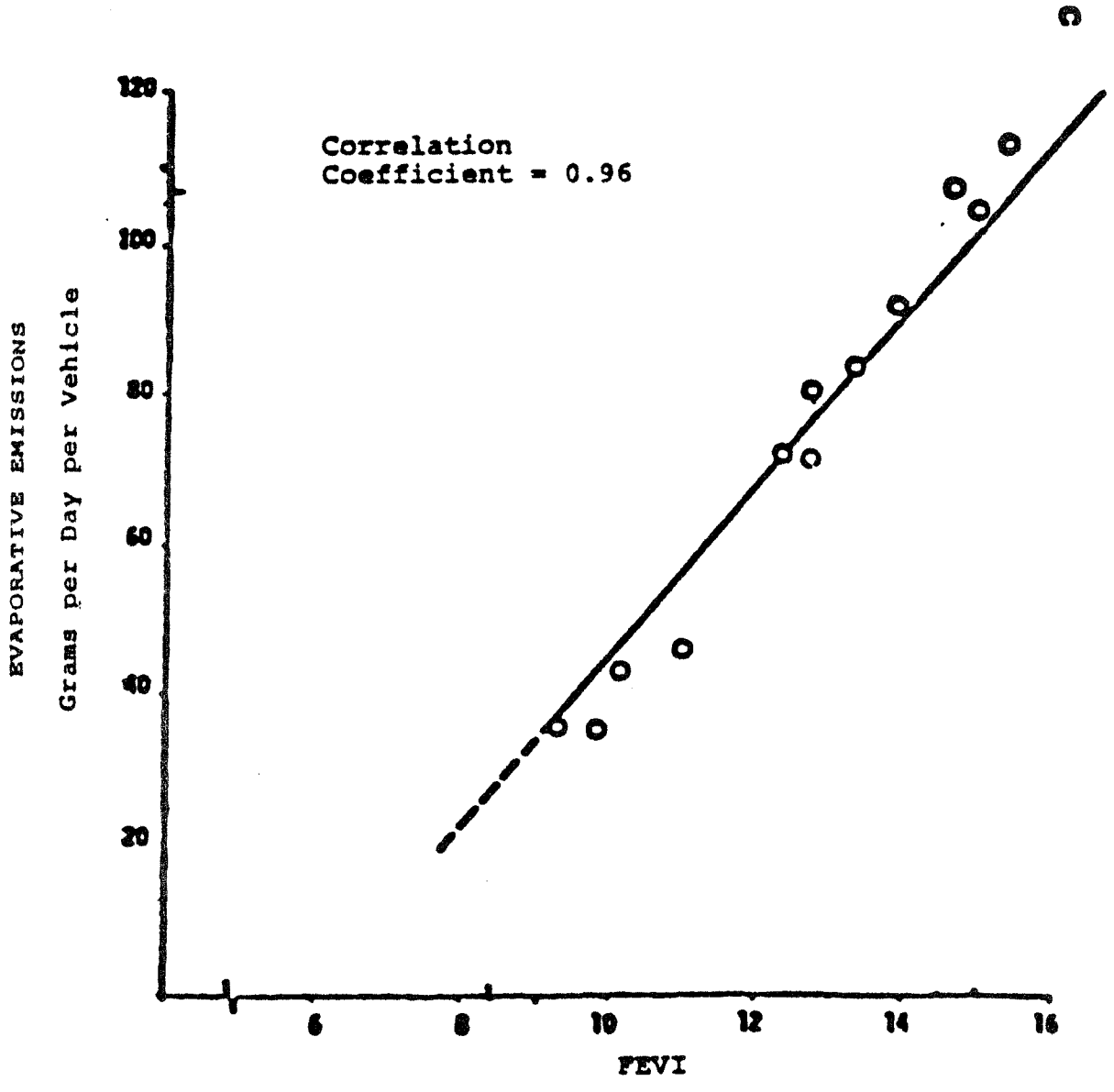


Figure 8-10. FEVI vs AUTOMOTIVE EVAPORATIVE EMISSIONS
(Source: ARCO, Ref. 16)

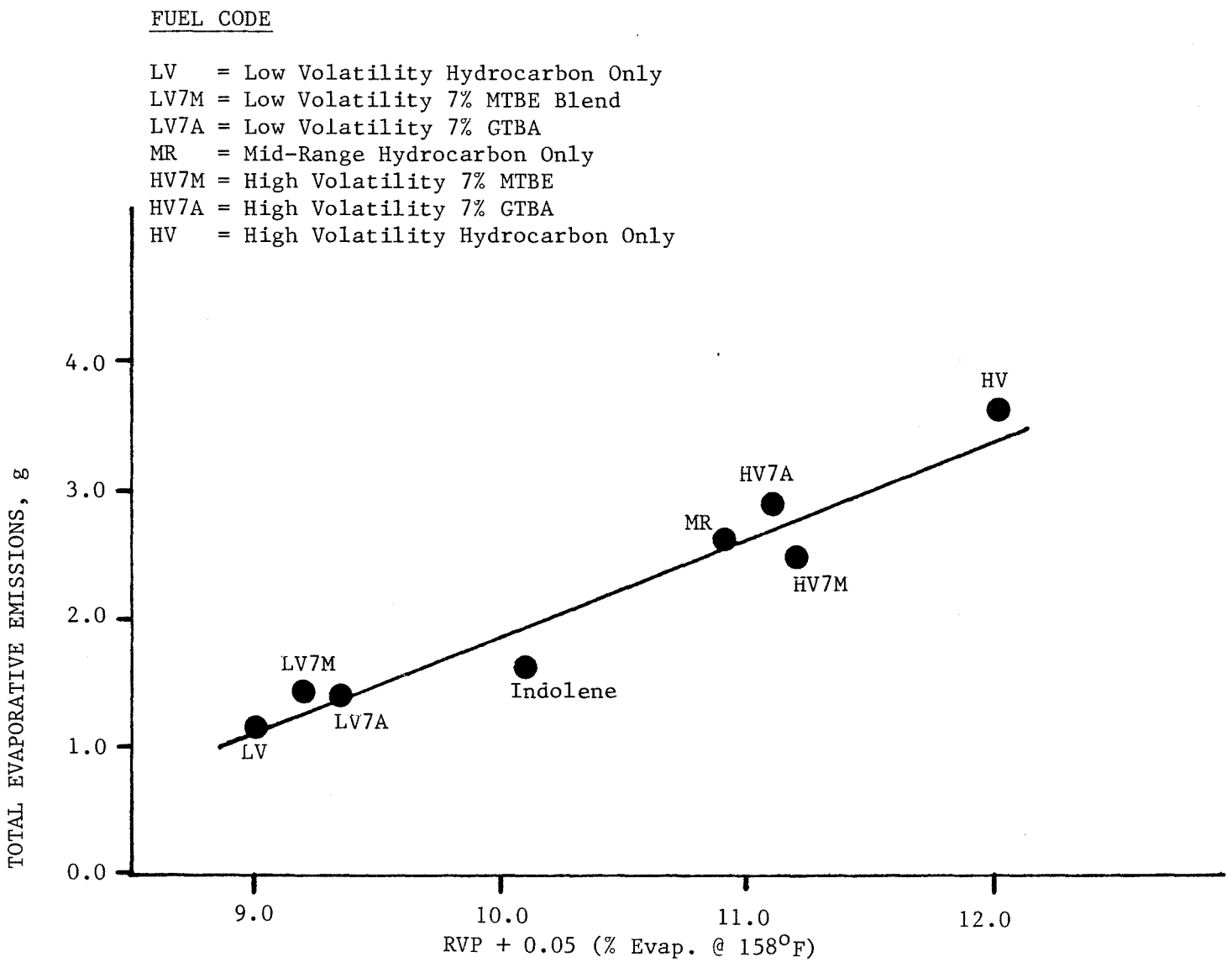
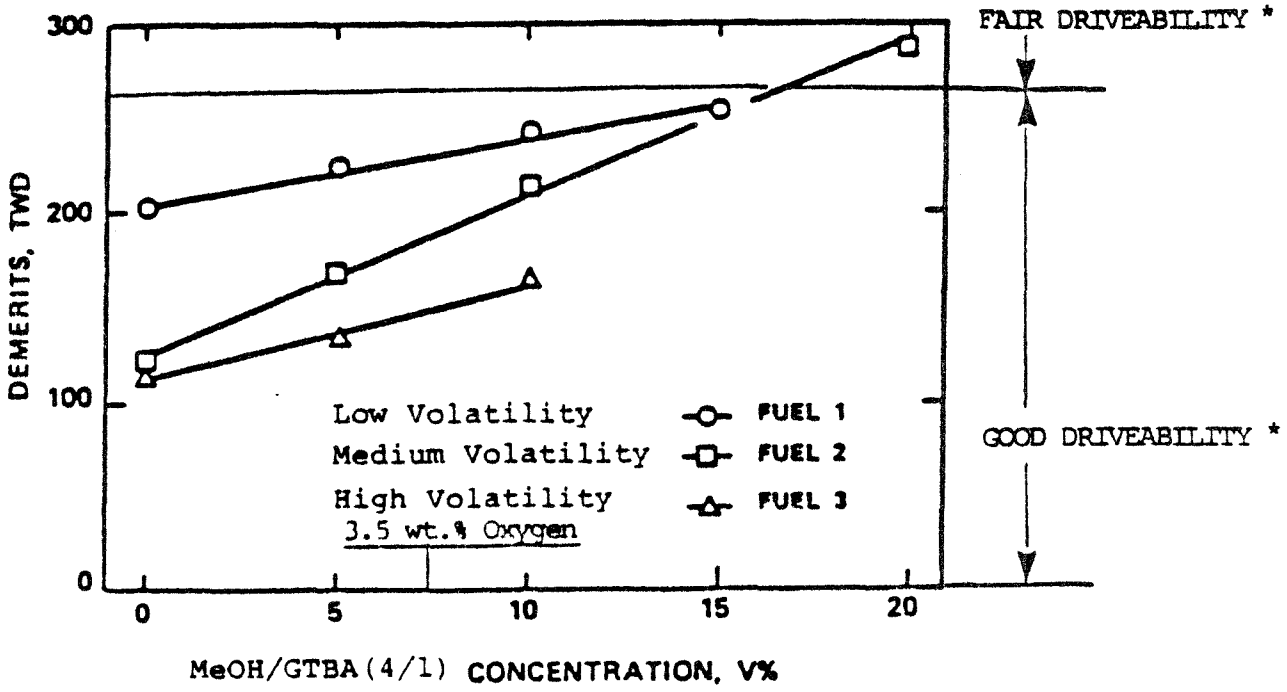
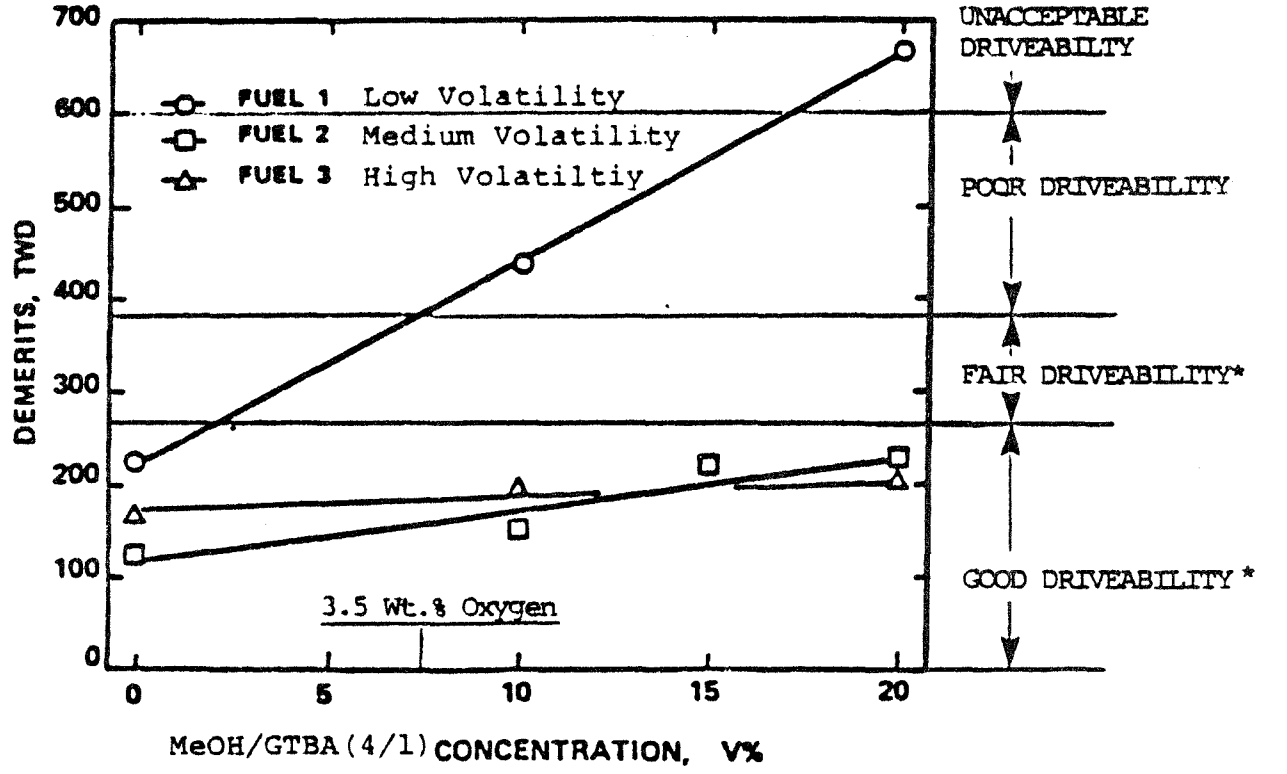


Figure 8-11. RELATIONSHIP BETWEEN FLEET AVERAGE EVAPORATIVE EMISSIONS AND FUEL VOLATILITY (Ref. 16)



* Fair and Good ratings are considered acceptable by consumers.

Figure 8-12. COLD DRIVEABILITY PERFORMANCE OF MeOH-BA IN A 1974 PINTO (CAL) AT 70°F (Source: ARCO, Ref. 16)



* Fair and Good ratings are considered acceptable by consumers.

Figure 8-13. COLD DRIVEABILITY PERFORMANCE OF MeOH-BA IN A 1974 PINTO (CAL) AT 35° ± 5°F (Source: ARCO, Ref. 16)

Table 8-4. FLEET TEST DRIVEABILITY RESULTS

	BASE	4.5V% MeOH 4.5V% GTBA	GASOHOL
% Trouble-Free Performance[a] Cold Engine	98	90	92
% Trouble-Free Performance[b] Hot Engine	99	99	99
% After Run-Free Performance[c]	99	99	100
% Knock-Free Performance[c]	99	99	100

[a] Maximum number of problems per start allowed by program = 3

$$\% \text{ Trouble-Free Performance} = 100 - \frac{\text{Problems}}{\$ \text{ (Starts)}} \; 100$$

[b] Maximum number of problems per driving period allowed by program = 3

$$\% \text{ Trouble-Free Performance} = 100 - \frac{\text{Problems}}{3 \text{ (Driving Periods)}} \; 100$$

[c] Maximum number of problems per driving period allowed by program = 1

$$\text{Problem-Free Performance} = 100 - \frac{\text{Problems}}{\text{Driving Periods}} \; 100$$

2. Potential Demand for Methanol by California Refiners and Gasoline Blenders

Methanol can enter the refinery-blending sectors by two possible paths. The first path is the direct use of methanol (with a suitable co-solvent such as tertiary butyl alcohol) as an octane enhancer. There currently exist EPA waivers permitting up to 4.5 percent methanol in conjunction with 4.5 percent TBA to be used in gasoline. This blending agent is currently being sold in PAD III by ARCO under the trade name Oxinol. Due to phase separation and vapor pressure, it is unlikely that methanol would be used without a co-solvent in PAD V (western district including California) or elsewhere. The second possible path for methanol is as a feedstock to the production of methyl tertiary butyl ether (MTBE) which is also used as a octane-blending agent. Neither use would contribute to the development or establishment of a retail methanol fuel infrastructure. However, these uses could expand or establish bulk methanol handling and transport facilities. These uses may also contribute to providing an elastic buffer for the discontinuous, large increases in supply which could occur as new methanol-producing facilities come on-stream. Either of these potential methanol options must

compete within PAD V with existing octane barrel costs, within complex integrated refineries, and/or with existing accepted octane-blending agents (MTBE, toluene, benzene, etc.) for the smaller refiners or with the blending-jobber sector.

The purpose of this brief analysis is to estimate the magnitude of potential demand for methanol in these markets. An estimate of the magnitude of potential demand for methanol will then permit an evaluation of whether or not the markets are large enough to perform the above-mentioned functions of establishing methanol handling and transport facilities and buffering discontinuities in methanol supply.

a. Potential MTBE Use by California Refineries. MTBE is an octane-blending agent for unleaded gasolines. MTBE has been used as a gasoline-blending component in Europe since the mid-70s, and in the United States since 1979. The maximum allowable concentration by volume of MTBE in gasoline is limited by EPA regulations to 11 percent. When it is used in blending unleaded gasoline, its concentrations are roughly 4 to 7 percent. MTBE is produced by reacting one part isobutylene with 0.57 parts methanol by weight. Representative MTBE production processes are schematically shown in Figure 8-14.

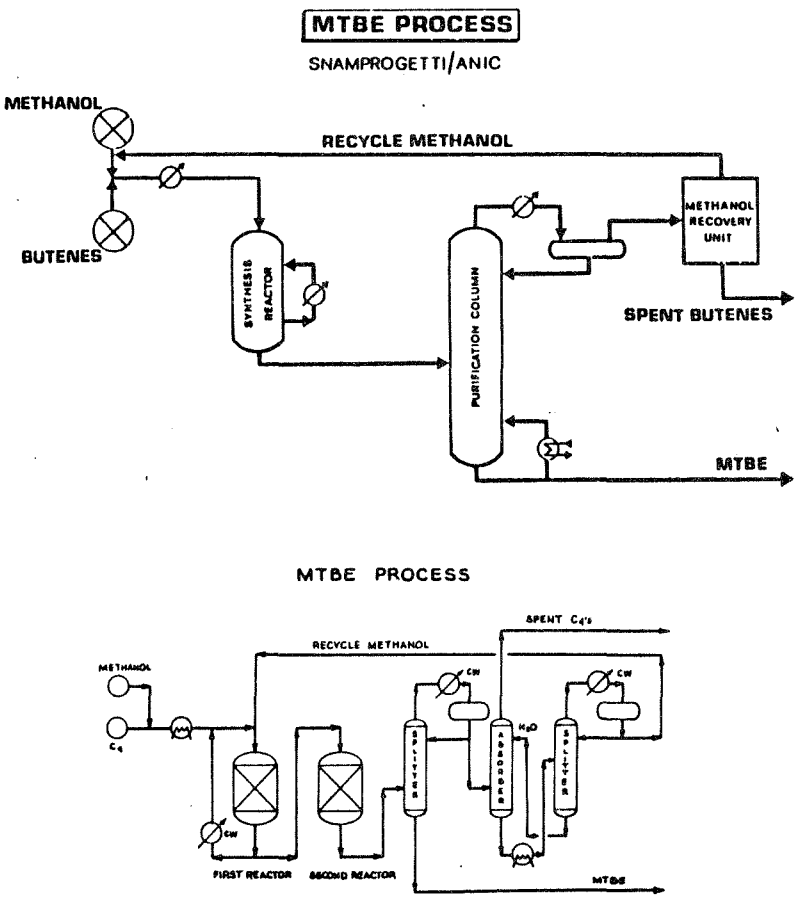


Figure 8-14. REPRESENTATIVE MTBE PRODUCTION PROCESSES (REF. 8,9)

Current production capacity for MTBE in the U.S. is 28,000 barrels per day (Ref. 8). This capacity is expected to increase to 35,000 to 42,000 barrels per day (Ref. 8). The limitation on production capacity of MTBE is due to the availability of isobutylene. There exist two sources of isobutelene: the C4 raffinate stream in an ethylene plant, and the C4 by-product stream from a fluidic catalytic cracking unit in a refinery.

Ethylene manufacturing plants are the principal source of isobutylene for MTBE production. A by-product of ethylene manufacture is the C4 raffinate, which, after butadiene removal, contains approximately 50 percent isobutelene. Because of the volume and the concentration of isobutalene, this is the most attractive source from a standpoint of manufacturing economics. The potential from ethylene plants for MTBE production has been estimated at 65,000 barrels (Ref. 3) per day. Actual capacity has grown from essentially 0 in 1970 to 28,000 (Ref. 4) barrels per day in 1982, and is expected to grow to between 35,000 and 42,000 (Ref. 5) barrels per day. This implies that for ethylene plants a significant fraction (60 percent) of the potential capacity is, in fact, expected to be realized.

The only other significant source of isobutalane is in the C4 olefin stream from a fluidic, catalytic cracking unit found in large, complex refineries. The potential production of MTBE in the U.S. from catalytic cracking units is 220,000 barrels per day (Ref. 6), which is approximately three-and-one-half times the potential from ethylene plants. Unlike ethylene plants, that potential is much more difficult to reach. This is due to several factors:

(1) The production economics are not as favorable as with ethylene plants. The concentration of isobutylene is roughly 10-15 percent of the C4 stream for the FCCU, whereas it is approximately 50 percent of the raffinate after butadiene extraction in the ethylene plant.

(2) Only a small number of refineries have FCCUs large enough to produce volumes equivalent to that produced by ethylene plants. For example, the potential production capability of the largest FCCU in California, the 60,000 barrel per day unit at the Mobil Torrance Refinery, could potentially produce approximately 900 barrels per day of MTBE. The smallest commercial MTBE facility in operation now produces 1,100 barrels per day of MTBE.

(3) If a refiner installs MTBE facilities, he is diverting the isobutylene from alkylation. A refinery with sufficient FCCU capacity to consider MTBE production already has in place existing alkylation units.

Whether or not MTBE will be produced in a refinery can only be properly judged on a refinery-specific analysis. However, one would not expect as rapid capacity growth as has been seen in ethylene plants.

Current U.S. production of MTBE is concentrated about the petrochemical industry in the Gulf states. The location and sizes of existing or under-construction plants are presented in Table 8-5. The Gulf States (PAD III)

Table 8-5. U.S. PRODUCERS OF METHYL TERTIARY-BUTYL ETHER, Their Plant Locations and Estimated Capacity (January 1, 1980-January 1, 1985, Ref. 11)

PRODUCER	PLANT LOCATION	ANNUAL CAPACITY			
		1980	1981	1981 1982	1983 1985
		--Thousand Short Tons--			
ATLANTIC RICHFIELD	Channelview, TX	200	200	200	200
CHAMPLIN PETROLEUM	Corpus Christi, TX				70
THE CHARTER COMPANY	Houston, TX		60	60	60
EXXON COMPANY USA	Baytown, TX			220	220
GOOD HOPE REFINERIES	Good Hope, LA	120	120	120	120
PHILLIPS PETROLEUM	Sweeny, TX			200	200
TENNECO, INC.	Houston, TX	280	280	280	280
TEXACO, INC.	Port Neches, TX			270	270
TOTAL		600	600	1350	1420

gasoline production is estimated for 1990 to be approximately 150 million barrels (Ref. 15). If 35 percent is premium unleaded-grade gasoline and MTBE was blended 4-7 percent in the unleaded grades of gasoline, it would more than exhaust expected MTBE production capacity. Hence, it is unlikely that significant amounts of MTBE would be exported outside of PAD III.

Due to the absence of ethylene plants within California, the near-term potential for methanol being used in MTBE production is limited. MTBE could potentially be produced from the larger fluidic cracking units in the larger refineries in the State of California. Table 8-6 presents the eight largest FCCUs in the state.

If MTBE facilities were installed within each of these refineries using the Gulf process (Ref. 14) for MTBE production, this would imply roughly 7.2 thousand barrels per day of MTBE production. This would require roughly 2.6 thousand barrels per day of methanol, or roughly 314 tons of methanol a day. If the utilization factor on these facilities was roughly 70 percent, this would reduce to an actual average consumption of 220 tons per day.

Relative to the volumes customarily associated with the refining sector within the State of California, methanol can be seen as potentially a very small feedstock into the production of gasoline. The potential methanol demand for MTBE is too small to cause the development of any significant supply and transport infrastructure. Furthermore, methanol demand from MTBE of the amount stated above is far too small to act as a buffer on methanol production from new methanol facilities.

Table 8-6. CALIFORNIA FLUIDIZED CATALYTIC CRACKING UNITS (Ref. 13)

REFINERY	CAPACITY (MBPO)
MOBIL/Torrance	60
ARCO/Carson	56
CHEVRON/Richmond	55
TOSCO/Avon	47
CHEVRON/El Segundo	47
EXXON/Bevicia	46
SHELL/Martinez	46
UNION/L.A.	46
	402

b. Potential Demand by California Refiners and Blenders for Methanol/TBA. To mitigate some of the undesirable properties of methanol used in gasoline blends, high molecular weight alcohols have been used. These high molecular weight alcohols both reduce the vapor pressure and significantly increase the water tolerance of the resulting blended gasoline. In addition, current EPA waivers permit methanol to be used only with such co-solvents. The most commonly used co-solvent is gasoline-grade tertiary butyl alcohol. While, in principle, many high molecular-weight alcohols could be used as co-solvents, TBA is the only one for which the price permits the resulting octane blending agent to be economically competitive. The waiver application granted to ARCO for its oxynol octane-blending agent specifically allows for maximum ratio by volume of one methanol to one gasoline-grade TBA (Ref. 16,17).

As MTBE utilization is constrainted by isobutylene availability. The use of methanol with a co-solvent is constrainted by the availability of TBA. TBA, like MTBE, is made exclusively in PAD III, and currently neither TBA nor oxinol is shipped to PAD V. TBA is made exclusively by ARCO with a production capacity of 25,000 B/D (3.8×10^8 gallon per year)(Ref. 18). At the waiver limitation of approximately 9 percent by volume of oxynol into unleaded gasoline, this limitation on TBA production capacity would allow for 8×10^9 gallon per year (30 percent of all PAD III unleaded) of unleaded PAD III gasoline production to be oxynol blended. In the perspective of California unleaded gasoline production, if the capacity limit production of TBA were shipped to California, this would allow for its blending in almost all (Ref. 12) of the PAD V unleaded gasoline production (Ref. 19, 20).

c. Toluene, MTBE, and Methanol Octane Barrel Costs Tradeoffs. One means for evaluating the economic viability of methanol containing blending agents is by calculating the octane number barrel costs, thereby comparing it to other commonly used blending agents. Octane number barrel costs will be defined as the cost in cents to raise the octane level of a barrel of gasoline one octane number, while preserving all other gasoline specifications. Three octane blending agents were chosen for comparison. The

ARCO oxinol agent (one to one mixture of 4.5 percent methanol and a tertiary butyl alcohol), methol tertiary butyl ether (MTBE), and toluene.

The economics of utilizing these blending agents for octane enhancement is affected by factors including: blending octane number, blending Reid vapor pressure; molecular weight, and cost. Table 8-7 presents the assumptions on blending octane number (used herein as Motor plus Research over two) and molecular weight. Density differences were ignored. It was assumed that octane numbers blend by volumetric proportions and vapor pressure blends by molar fraction proportions. Figure 8-15 presents the assumed blending Reid vapor pressure (in pounds per square inch) as a function of the blending agent concentration in the finished gasoline. It was assumed that vapor pressure reduction through the addition of high-molecular weight co-solvents to methanol was a result of the increase in molecular weight in the blending agent. Hence, the given curve is appropriate for both methanol and methanol with co-solvents when adjustment is made for increasing molecular weight.

The procedure used to calculate the octane number of barrel costs was as follows: an 87 [(R+M)/2] octane number gasoline with a RVP of 10 psi containing 5 percent butane was assumed. An octane-blending agent was added sufficient to raise the octane one octane number and butane was adjusted to maintain the one octane number increase and the 10 psi RVP. A similar calculation was performed for a 91 octane number premium grade unleaded. The cost of the 87 octane gasoline was assumed to be $1; the cost of the 91 octane number gasoline was assumed to be $1.05; the price of butane was assumed to be $0.60/gallon. The difference in cost between a barrel of the original gasoline and a barrel of the final gasoline was defined as the octane number barrel cost.

Figures 8-16 and 8-17 present the results of these octane number barrel cost calculations. The vertical axis is the octane number of barrel cost in cents per octane number barrel; and the horizontal axis is the cost of the octane blending agent in cents per gallon. A difference of prices between PAD III and PAD V was assumed to be in the range of $0.12 to $0.14 per gallon for all of the octane blending agents (in some cases, PAD III may not be the least cost choice and the difference may be less). Both Figures 8-16 and 8-17 show a slight octane barrel cost advantage for MTBE over toulene with the difference being most pronounced for the premium grade blending. Also in both cases, it

Table 8-7. BLENDING OCTANE NUMBER AND MOLAR WEIGHT OF SELECTED BLENDING AGENTS

	BLENDING OCTANE NUMBER (R + M)/2	MOLAR WEIGHT
TOLUENE	103.5	92.0
MTBE	109.0	88.0
METHANOL	119.5	32.0
ETHANOL	117.5	52.0
OXINOL	105.5	53.1

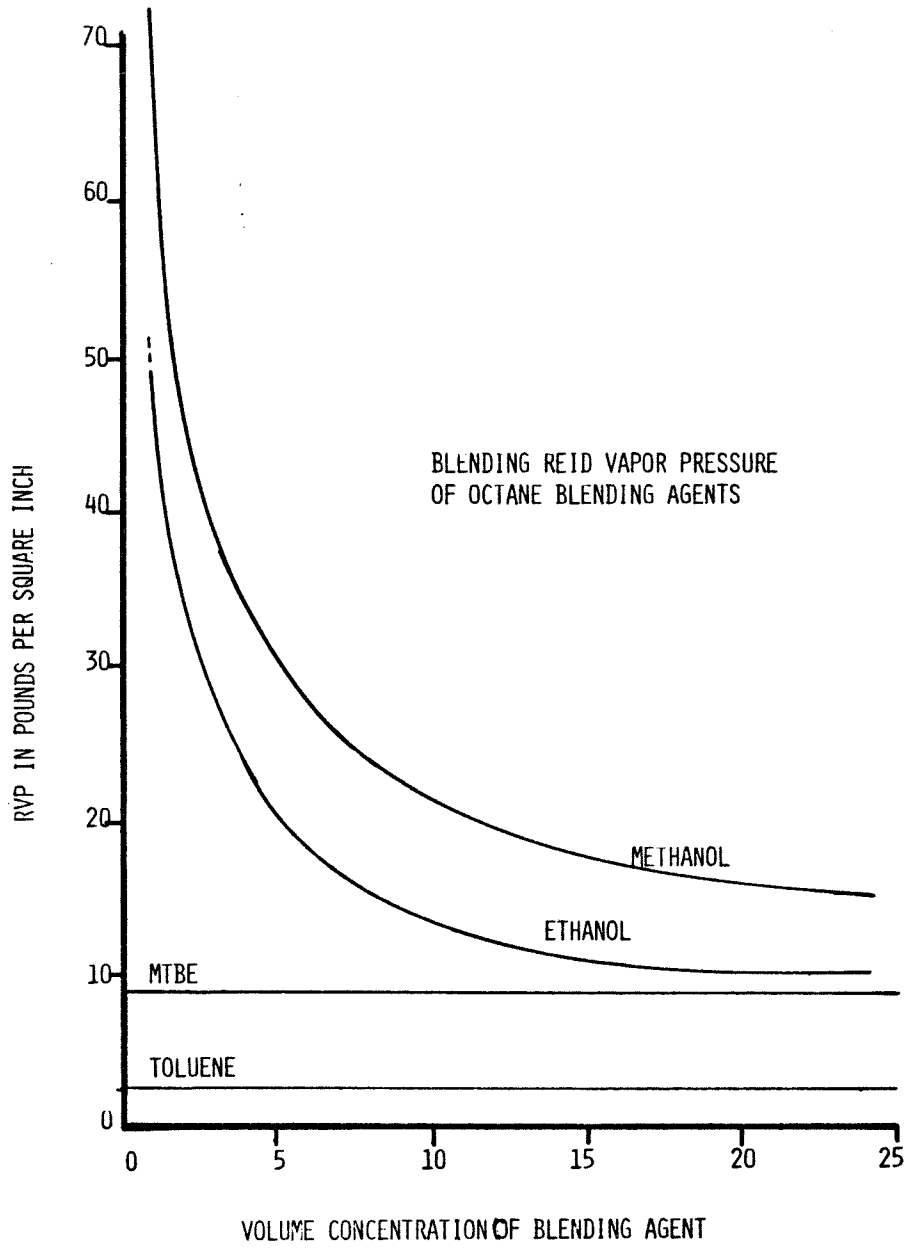


Figure 8-15. BLENDING REID VAPOR PRESSURE OF OCTANE BLENDING AGENTS

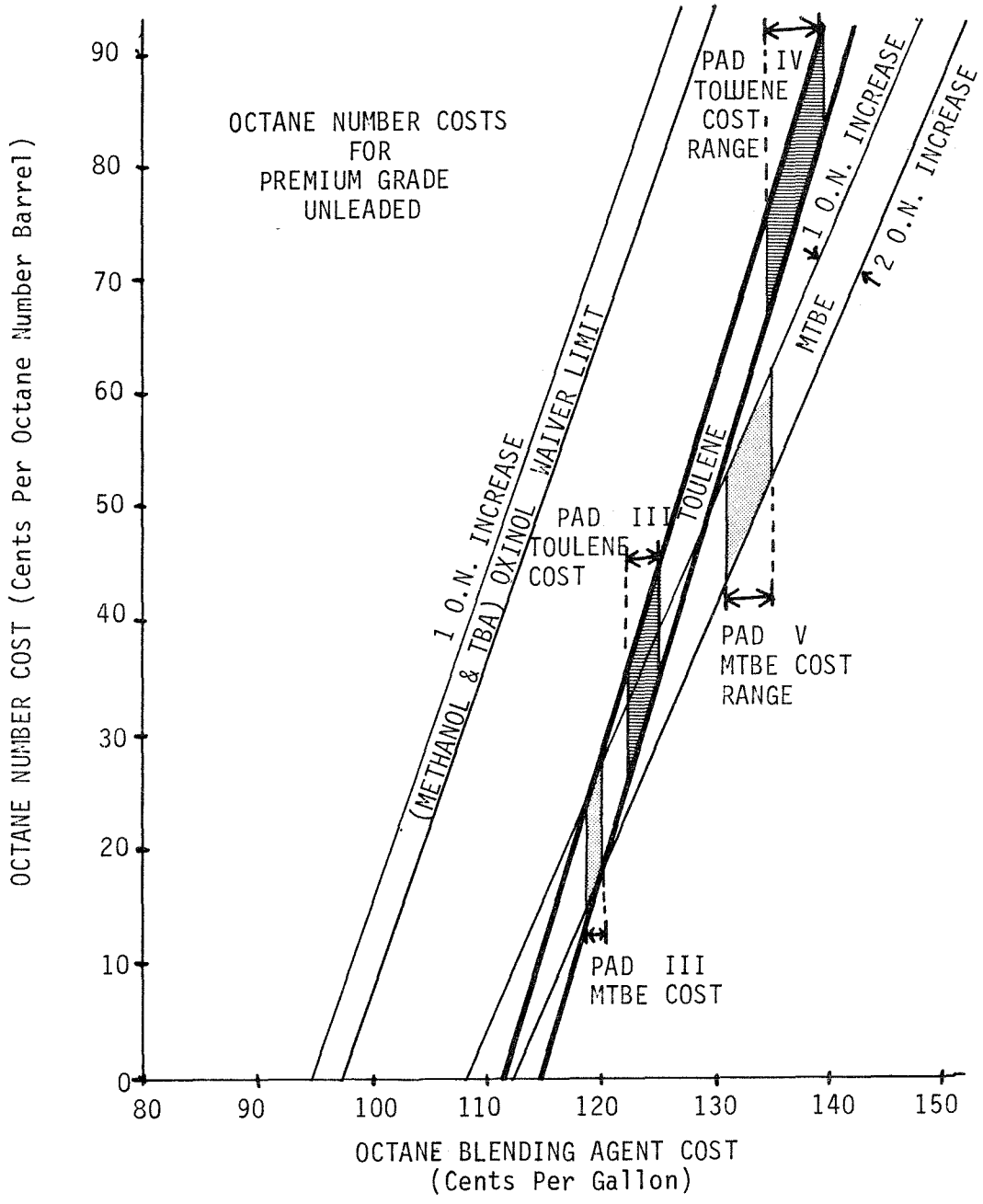


Figure 8-16. OCTANE BLENDING AGENT COST
(cents per gallon)

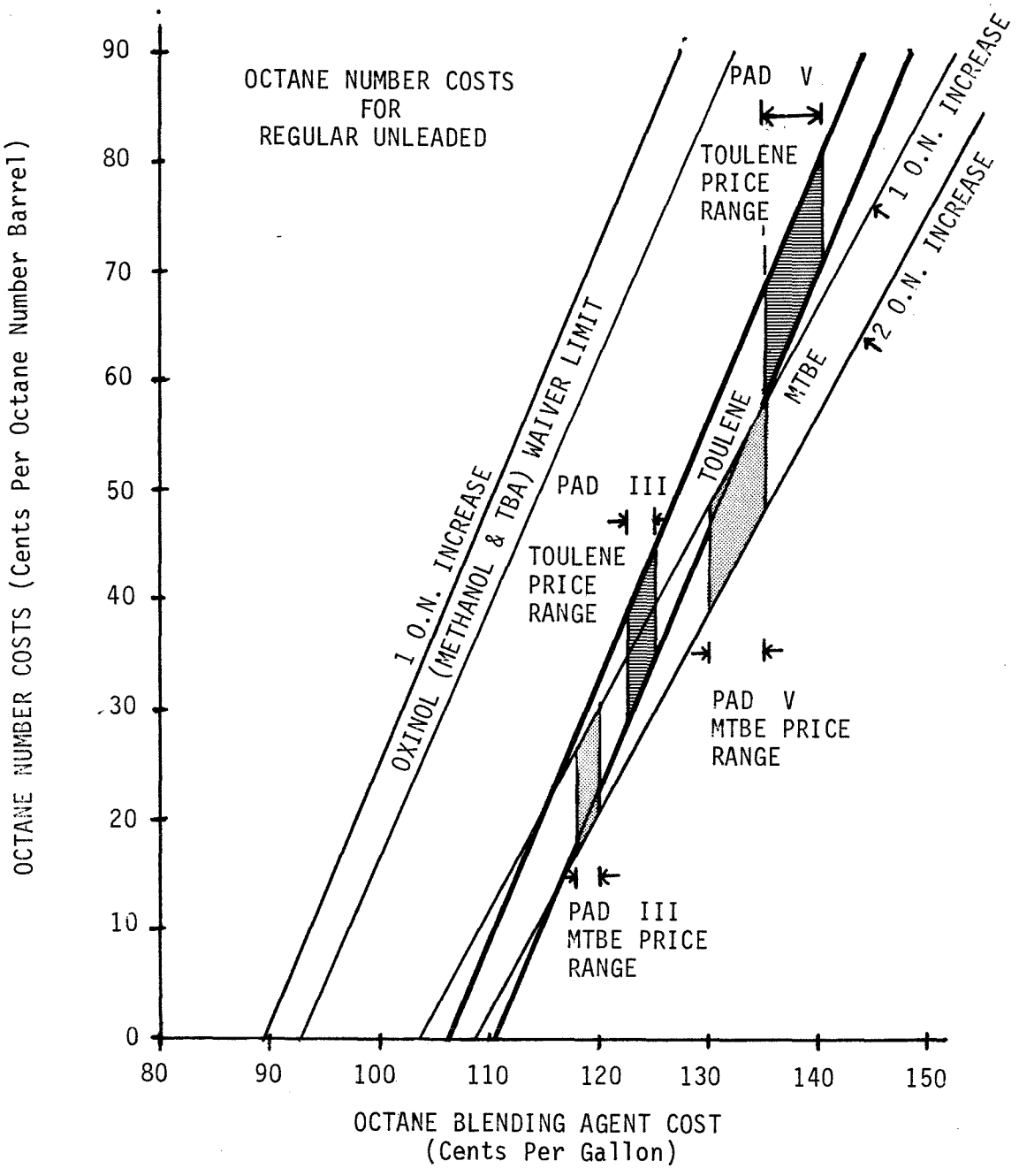


Figure 8-17. COST OF OCTANE BLENDING AGENT

shows oxinol at $1 per gallon and at waiver limit blending to be slightly less expensive than MTBE in PAD III. These relationships also show a higher evaluation for oxinol in premium-grade blending than in regular-grade blending, which under a TBA production constraint is consistent with current use of oxinol. The portions of the curves labeled "PAD V costs" result from an assumption of 12 to 14 cents per gallon shipping costs from PAD III to PAD V. Due to the steepness of these curves, the additional cost of shipping profoundly affects the octane number of barrel cost for these blending agents. For example, premium-grade blending toluene in PAD III is approximately $0.35 an octane number barrel, whereas under these calculations in PAD V, it is approximately $0.85 per octane number barrel. This is also consistent with the observation that few, if any, of the complex integrated refineries within PAD V use PAD III-produced octane blending agents in their gasolines.

Figure 8-18 presents the results of these octane number barrel costs for PAD V, presented parametrically in terms of West Coast methanol price. The oxinol curve assumes that the tertiary butyl alcohol costs $1.10 in PAD III and has an effective cost of $1.25 in California. The curve labeled PAD V MTBE assumes that MTBE could be produced in PAD V with the same production economics as from PAD III ethylene plants. From these results, the following inferences can be made. At approximately $1.05 per gallon methanol, oxinol becomes competitive with MTBE imported from PAD III. In all cases, oxinol is a more economic way to enhance octane than PAD V-produced MTBE. At approximately $0.62 per gallon and $0.72 per gallon, oxinol becomes price competitive as a volume enhancer for regular- and premium-grade gasolines, respectively. If the octane number barrel cost for complex integrated refineries in California is between $0.20 and $0.40 per octane number barrel, this implies that oxinol would be competitive in this market at West Coast methanol prices between $0.80 to $0.95 per gallon. It should be noted that octane number barrel costs vary between refineries and a preferred blending agent for one may not be for another. This simplied analysis cannot capture such distinctions.

d. Methanol Demand. Table 8-8 shows the expected 1985 production of gasoline in California. This is from recent work of both Bonner and Moore and Booz and Allen for the California Energy Commission (Ref. 19, 20). Integrating this gasoline production information with the results of the previous analysis, a very approximate price-demand relationship for methanol in Calif. ornia can be derived. Fifty cents an octane number barrel is approximately the cost for upgrading regular gasoline with premium-grade or by increasing octane through the use of PAD III imported MTBE. If we assume that $0.50 is the approximate octane barrel cost for the smaller topper and hydro-skimming refineries in California, methanol would become economical in the submarket at approximately $1.05 per gallon. If we assume a octane number barrel cost of $0.20 for premium unleaded gasoline produced by complex integrated refineries within California, this would imply methanol viability at approximately $0.95 per gallon. In a similar fashion, it would become economical at approximately $0.85 for regular unleaded octane blending. At approximately $0.70 per gallon, methanol would become competitive for volume blending in the premium grades of gasoline and, likewise, at about $0.60 per gallon in the regular grades of gasoline for the complex integrated refineries. These relationships are graphically summarized in Figure 8-19. This figure shows approximately 4 percent of the California gasoline becoming candidates for methanol blending

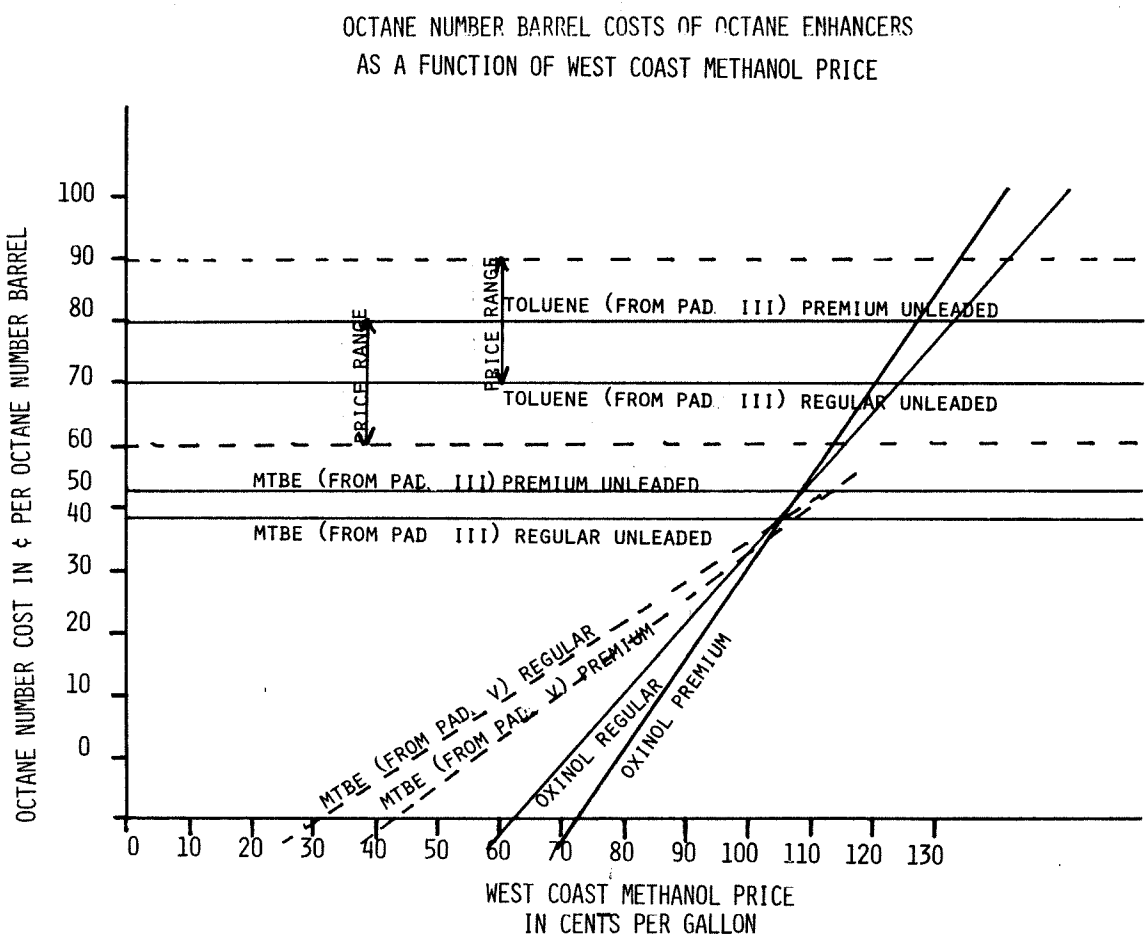


Figure 8-18. OCTANE NUMBER BARREL COSTS OF OCTANE ENHANCERS AS A FUNCTION OF WEST COAST METHANOL PRICE

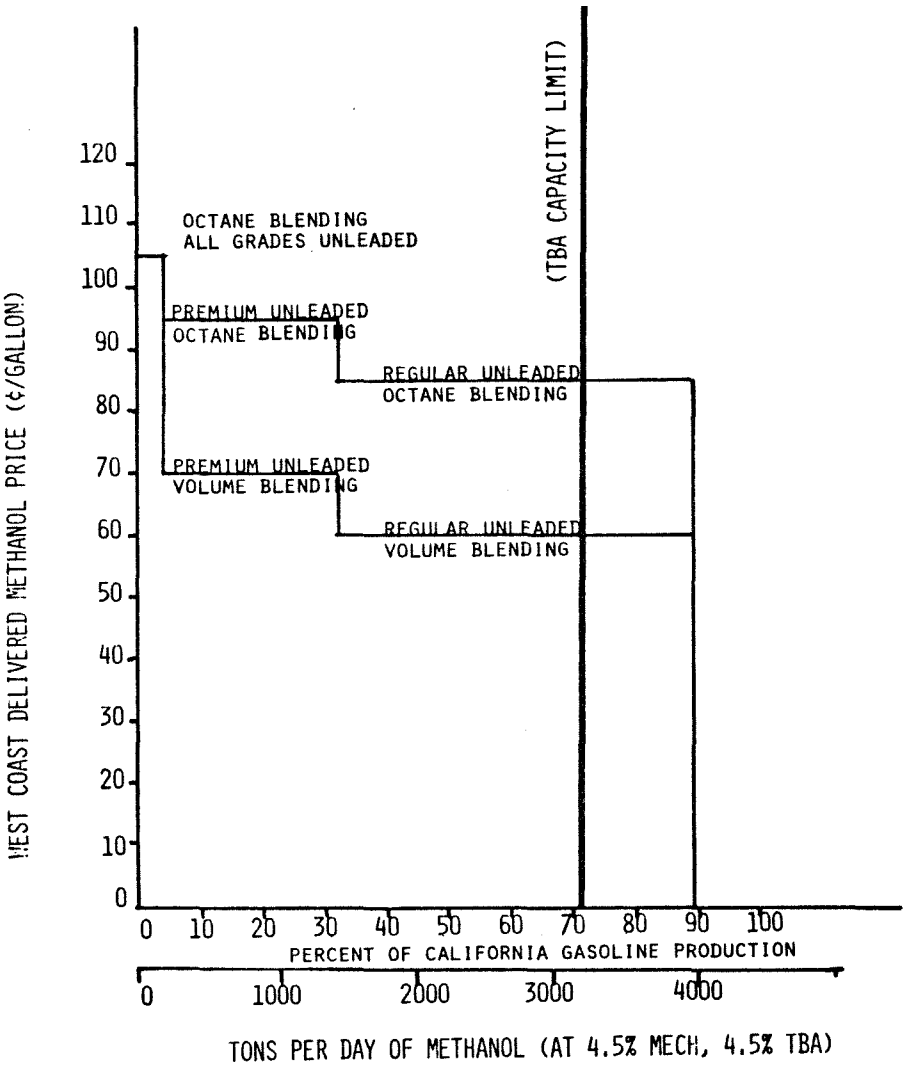


Figure 8-19. PRICE DEMAND RELATIONSHIP FOR METHANOL BY CALIFORNIA REFINERS AND BLENDERS

Table 8-8. CALIFORNIA GASOLINE PRODUCTION FORECASTS

YEAR	MBPD BY TYPE OF REFINERY								
	COMPLEX			HYDRO-SKIMMERS			TOPPERS		
	REGULAR UNLEADED	PREMIUM UNLEADED	LEADED	REGULAR UNLEADED	PREMIUM UNLEADED	LEADED	REGULAR UNLEADED	PREMIUM UNLEADED	LEADED
1978	209.1	0	527.2	10.4	0	31.9	0	0	4.4
1985	159.5	382.5	191.8	25.5	4.5	9.1	0	0	4.1
1992	194.5	382.4	61.6	22.6	7.5	3.9	0	0	3.5
2000	175.7	353.5	57.4	18.5	9.3	3.4	0	0	3.2

at approximately $1.05 per gallon for methanol. In the complex integrated refineries, the demand is bounded between octane blending and volume blending with a major increase in demand somewhere in the $0.80 per gallon range. Up to approximately 4000 tons of methanol a day could potentially be consumed by the California refiners and blenders at a methanol price of approximately $0.70 per gallon. Such use, however, is completely dependent upon the availability in PAD V of a economical co-solvent for the methanol. The only inexpensive co-solvent currently available in the U.S. is ARCO's tertiary butyl alcohol. The U.S. TBA production capacity limit is shown by the vertical line in Figure 8-19, equivalent to waiver limit blending of 72 percent of California gasoline production. This implies that the demand for methanol by California refineries is not strongly dependent upon methanol prices because a large potential demand exists at prices greater than existing market prices. But, rather, it is dependent upon decisions to ship tertiary butyl alcohol from its point of production in PAD III to the California refinery market.

e. Gasoline Vapor Pressure Limits and Methanol Blends. To reduce evaporative hydrocarbon emissions into the atmosphere, the vapor pressure of gasoline is limited to 9 pounds Reid Vapor Pressure during the warmer months of the year. The portion of the year to which this limitation applies varies by Air Quality Districts. For example, in the South Coast district, it is between April 1 to October 30; whereas in the Bay Area it is from May 1 to October 30. If a methanol gasoline blend is used during this portion of the year, it must be blended with a gasoline of low-vapor pressure and/or a high proportion of heavy alcohol co-solvent must be used with the methanol. To reduce the vapor pressure of the base gasoline sufficiently so as not to exceed the 9 pound limit after the methanol is blended requires a significant reduction in the most volatile components (principally butane) of the base gasoline. Since butane on a per-gallon basis is less expensive than gasoline, its reduction will have a negative impact on the economic viability of the methanol blend. This limitation may also rule out terminal blending of the methanol and force such blending to be done at the refinery where a specially-tailored, low-volatility gasoline may be available.

Figure 8-20 presents octane number barrel (ONB) costs for a methanol blending agent as a function of the RVP of the finished gasoline. As can be seen, as the RVP is reduced, the cost to increase octane becomes greater. This result is for a specific case described as follows:

- Original gasoline: Cost = $1.00/gal for all RVPs
  Butane content = 5% for all RVPs
  Octane number $(\frac{R\&M}{2}) = 87$
- Octane increasing agent: 50% methanol, 50% TBA at $1.00 per gallon
- Finished gasoline: Same RVP as original gasoline
  Octane number = 88

The higher ONB costs of lower RVPs will lower the value of methanol and methanol/TBA. In the previous 10-lb RVP example, the methanol breakeven price for volume blending was $.60 to $.70 per gallon (octane blending price of $.85 to $.95). A limit of 9 lbs RVP would reduce the value by $.03 to $.04 per gallon.

It should be noted that the results shown in Figure 8-20 are only very approximate, and a detailed refinery cost linear programming analysis should be performed at a refinery-specific level to determine more accurate values.

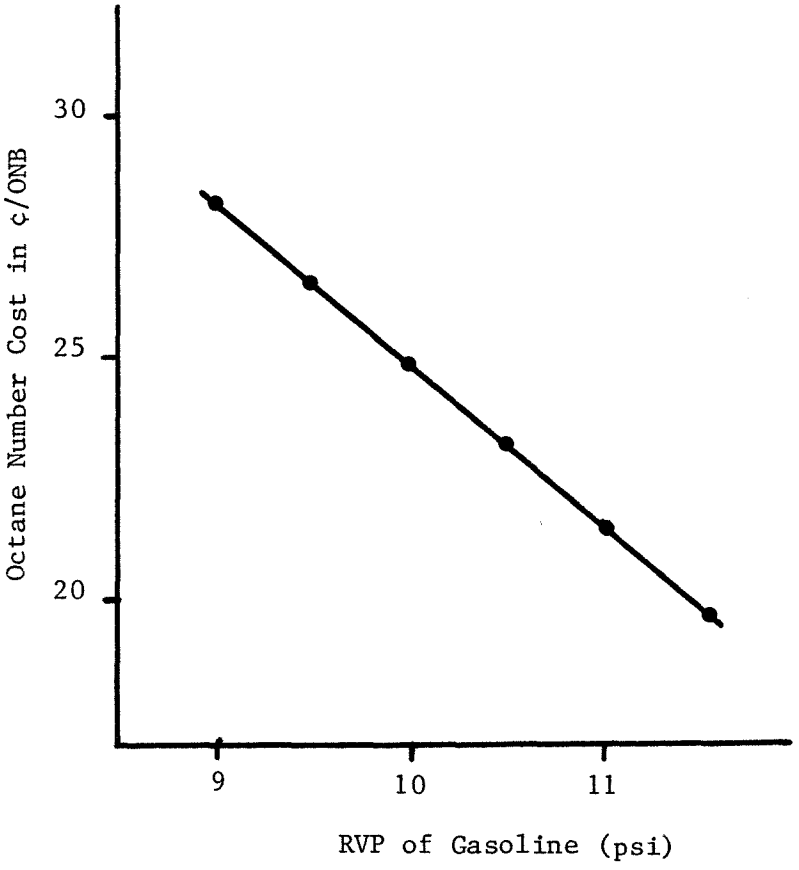


Figure 8-20. OCTANE NUMBER BARREL COST FOR A METHANOL/TBA BLENDING AGENT AS A FUNCTION OF RVP

B. NEAT METHANOL AS A FUEL

Methanol is a slightly heavier liquid (about 2 percent greater density) than gasoline. Methanol boils at 149°F, while components of gasoline boil at temperatures ranging from about 80° to 400°F. The lower heating value of methanol is less than one-half that of gasoline. The latent heat of vaporization, on the other hand, is over three times as great. The vapor pressure of methanol is less than that of gasoline and the stoichiometric air-fuel ratio is also considerably less (6.4 vs 14.5). Whereas water is basically insoluble in gasoline, it is infinitely soluble in methanol. The comparative properties of methanol and gasoline is given in Table 8-9.

The phase separation problem associated with blends is eliminated with the use of neat methanol as a transportation fuel. Neat fuel does require an engine and fuel system designed or modified for such operation. Problems which must be addressed relative to the use of pure alcohol include material compatibility, aldehyde exhaust emissions, cold starting, and potential abnormal engine wear.

Table 8-9. PROPERTIES OF METHANOL AND GASOLINE (Ref. 21)

	METHANOL	GASOLINE
CHEMICAL FORMULA	CH_3OH	Mixture of C_4-C_{12} hydrocarbons
Molecular Weight	32.04	100-105 (Avg.)
Composition, wt %		
Carbon	37.5	85-8
Hydrogen	12.6	12-15
Oxygen	49.9	0
Specific Gravity (60°F)	0.796	0.72 - 0.78
Density, g/cm^3 (lb/gal)	0.794 (6.63)	0.695-0.779 (5.8-6.5)
Boiling Temperature °C (°F)	65 (149)	27 - 225 (80 - 437)
Flash Point, °C (°F)	11 (52)	-43 (-45)
Auto Ignition Temperature, °C (°F)	464 (867)	257 (495)
Flamability Limits, vol %		
Lower	6.7	1.4
Higher	36	7.6
Heating Value, Lower kJ/kg (Btu/lb)	19,930 (8,570)	43,960 (18,900)
Latent Heat of Vaporization, kJ/kg (Btu/lb)	1,177 (506)	349 (150)
Vapor Pressure, kPa at 38°C (psia at 100°F)	31.9 (4.6)	38 - 103 (7 - 15)
Stoichiometric A/F	6.4	14.2 - 14.8
Water Solubility	Infinite	Insoluable

The effects of pure methanol upon vehicle performance are discussed in the following material. The parameters considered include driveability, power, and fuel consumption. Specific vehicle modifications will be discussed when appropriate to achieving certain objectives using methanol.

1. Driveability

Driveability problems caused by the vaporization characteristics of methanol may be a concern. Proper design of vehicles for methanol to avoid these problems should be possible.

a. Cold Startability. The low vapor pressure of neat methanol at ambient temperature (2 psi as compared to at least 6.5 psi RVP for gasoline) causes vaporization problems during cold starts. Even under choked carburetor conditions, a flammable mixture may not be attainable that would enable a cold engine to start below about 40°F. By contrast, the lower boiling gasoline components provide sufficient volatility to ignite gasoline at very low temperatures, (-22°F or less). Reports indicate that volatile materials such as isopentane and di-methyl ether can be added to reduce the cold-start problems. The cost and availability of these light hydrocarbons must, of course, be considered. The approach of adjusting fuel volatility is not new. Winter gasolines, for example, contain more volatile hydrocarbons than do summer gasolines, to allow proper starting under winter conditions. Gasoline volatility is tailored for climate, location and regulation requirements.

Other methods of enhancing cold starting with alcohol fuels have been successfully demonstrated. These include electric heating of the intake manifold to accelerate fuel vaporization, and the use of dual (auxiliary) fuel systems such as gasoline or propane. The latter systems utilize a "cold start" system to supply an onboard volatile fuel component to the engine intake air during choke operation. Once the car has started and is warmed-up, fuel delivery from the auxiliary system is terminated.

The auxiliary heating method uses an electrical resistance heater operated with power from the car's battery to vaporize the fuel. This technique, however, draws heavily on the battery at the same time the starting motor is drawing maximum current. After the engine has started, heat must continue to be applied during early warm-up until exhaust heat can maintain the fuel vaporizing task. The ultimate solution to the cold-startability of neat methanol, overall ambient temperature ranges, may be a combination of fuel volatility control and some auxiliary electric manifold heating technique.

An advantage of methanol, however, is that once the vehicle has reached the warmed-up condition, it can be operated at much leaner equivalence ratios than gasoline for the same level of driveability. This characteristic of methanol will be discussed in the next section. However, it may not be compatible with three-way catalyst operation if the feedback system requires a near stoichiometric mixture.

b. Lean Combustion. Leaner than stoichiometric mixtures can be used with methanol without causing driveability problems. Leaner mixtures

characteristically give lower emission levels for hydrocarbons and CO, hence the use of neat methanol offers an advantage. According to Ingamells (Ref. 22), at 14 percent lean, methanol showed better driveability, improved thermal efficiency, and much lower carbon monoxide and nitrogen oxide levels compared to gasoline running only 5 percent lean.

The leaner operation results in higher engine thermal efficiencies and, therefore, the number of miles traveled per Btu can be greater than for gasoline. It is possible to operate at a higher energy efficiency with methanol because of its lower lean misfire limit, and higher compression ratios.

2. Fuel Consumption

The volumetric energy content (Btu/gallon) of methanol is approximately one-half that of gasoline. However, the higher ON of methanol permits the use of higher compression ratio engines which allow gains in thermal efficiency for a methanol-fueled engine. Compression ratios in the range 11:1 to 14:1 appear feasible. For example, the CEC Fleet Two vehicle used 12.5:1 compression ratios. This could result in significant thermal efficiency improvements. Previously mentioned CEC tests on a Fleet Two vehicle imply up to a 14 percent improvement. Methanol fuel economy (miles/gallon), therefore, could be as much as 40 percent poorer than that obtained with gasoline despite the combined effects of higher compression ratio and leaner equivalence ratio operation. This means for a liquid methanol-powered car the fuel tank would have to contain approximately 67 percent more fuel than one for gasoline to drive a fully-optimized vehicle the same distance. If exhaust heat were used to vaporize or dissociate liquid methanol, the fuel tank would have to contain about 50 percent more fuel than for gasoline.

Depending upon vehicle design, a larger fuel tank could require some sacrifice in trunk space. Carrying a greater number of gallons would also increase the weight of the car, thereby causing a slight loss in vehicle fuel economy. Since methanol engines produce greater specific power compared to gasoline engines, future methanol engines can probably be downsized. This reduction in engine weight could counter the increase due to carrying a greater weight of fuel. Thus, although the car weight may not increase, internal volume would be sacrificed to the larger fuel tank.

3. Power Output

When burned in an internal combustion engine, more power can be obtained with methanol because its higher latent heat of vaporization cools the air entering the engine much more than does gasoline, and this increases the engine's volumetric efficiency. Higher specific power can also result from the "fast burn" characteristics of methanol. The gain in power output from an engine using methanol, aside from other gains due to increased compression ratio, is as much as 10 percent if very rich fuel mixtures are used. For this reason, methanol has been used for many years in automobile racing. The gains in power due to this effect are smaller (6% to 8%) when used in passenger cars operating with normal mixtures.

Figure 8-21 presents brake horsepower comparisons of both methanol and ethanol fuels with indolene as a function of air-fuel mixture equivalence ratio. Comparative engine thermal efficiency results for these same fuels are given in Figure 8-22. As shown, methanol provides the greatest gains in both thermal efficiency and brake horsepower. These improvements could probably be increased even further by increases in engine compression ratio and/or by turbocharging.

4. Abnormal Combustion Phenomena

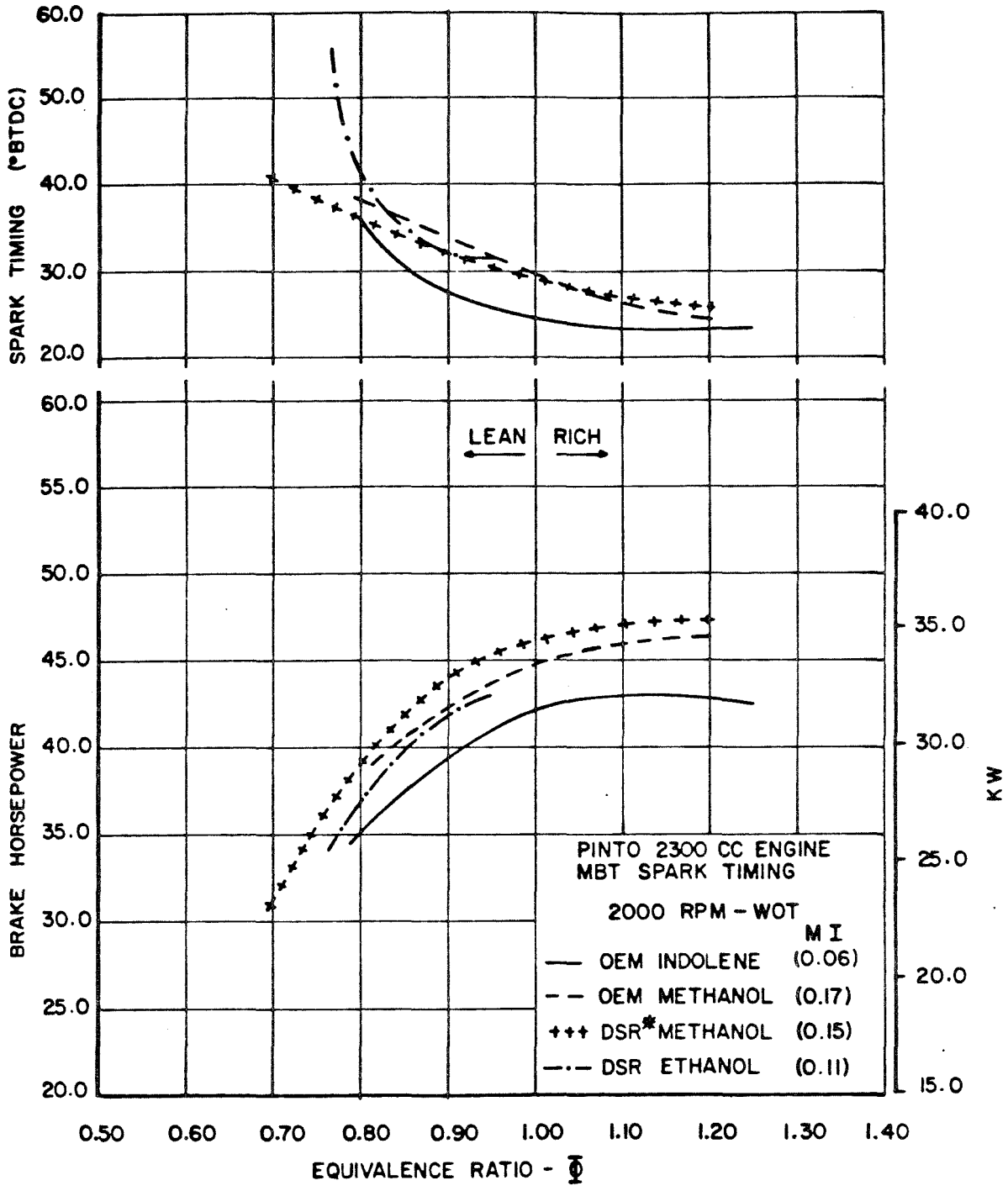
Although the ASTM octane ratings of methanol are high, combustion preignition problems at high engine-power ranges may limit comprssion ratios. Engine operation above some threshold limit has been observed (Ref. 23) to cause rough running, combustion noise, and even hardware failure. A probable source of preignition has been identified as a hot spark plug. Further research has been identified to better understand this combustion-related problem.

5. Typical Results with Neat Methanol

Additional research efforts have also been reported by Brinkman (Ref. 26) of General Motors concerning the use of neat methanol in two vehicles. The basic difference between the two V-8 powered cars was the engine induction system. One vehicle was equipped with a stock carburetor while the other had electronic fuel injection (EFI). The carbureted car had increased intake mixture heating and was tested with various intake manifolds. The objectives of this research study were to evaluate vehicle driveability, determine exhaust emissions and fuel economy, and to access the effect of equivalence ratio and spark timing on these parameters.

a. Driveability. Although eight different combinations of intake manifolds, intake air heating and exhaust gas heating were evaluated with the carbureted car, no single induction system was found to give adequate driveability with neat methanol. This fact is illustrated by Figure 8-23 which compares the cold-start driveability of both fuels. Driveability of the EFI car with methanol was good; it was even better than the carbureted car using gasoline. The EFI car was used for the other tests, since this was the only configuration with acceptable driveability using neat methanol.

b. Exhaust Emissions. Emissions data for the methanol-fueled EFI car were obtained using the production spark timing and a 0.96 equivalence ratio. The comparative test results are shown in Figure 8-24, measured on both sides of an oxidation exhaust catalyst. Methanol exhibited lower NO_x emissions, probably due to its lower combustion temperature. Both the engine and tailpipe emissions of CO were similar, since the vehicles were operated near the same equivalence ratio. The unburned fuel in the exhaust was 3.5 times greater with methanol. Less than 2 percent of the total tailpipe emissions, however, were hydrocarbons. The remaining unburned fuel emissions were a mixture of methanol and aldehydes.



OEM = Original Carburetion
DSR = Dresserator Carburetion

Figure 8-21. COMPARISON OF BRAKE HORSEPOWER FOR SEVERAL ENGINE INDUCTION SYSTEMS (Ref. 5).

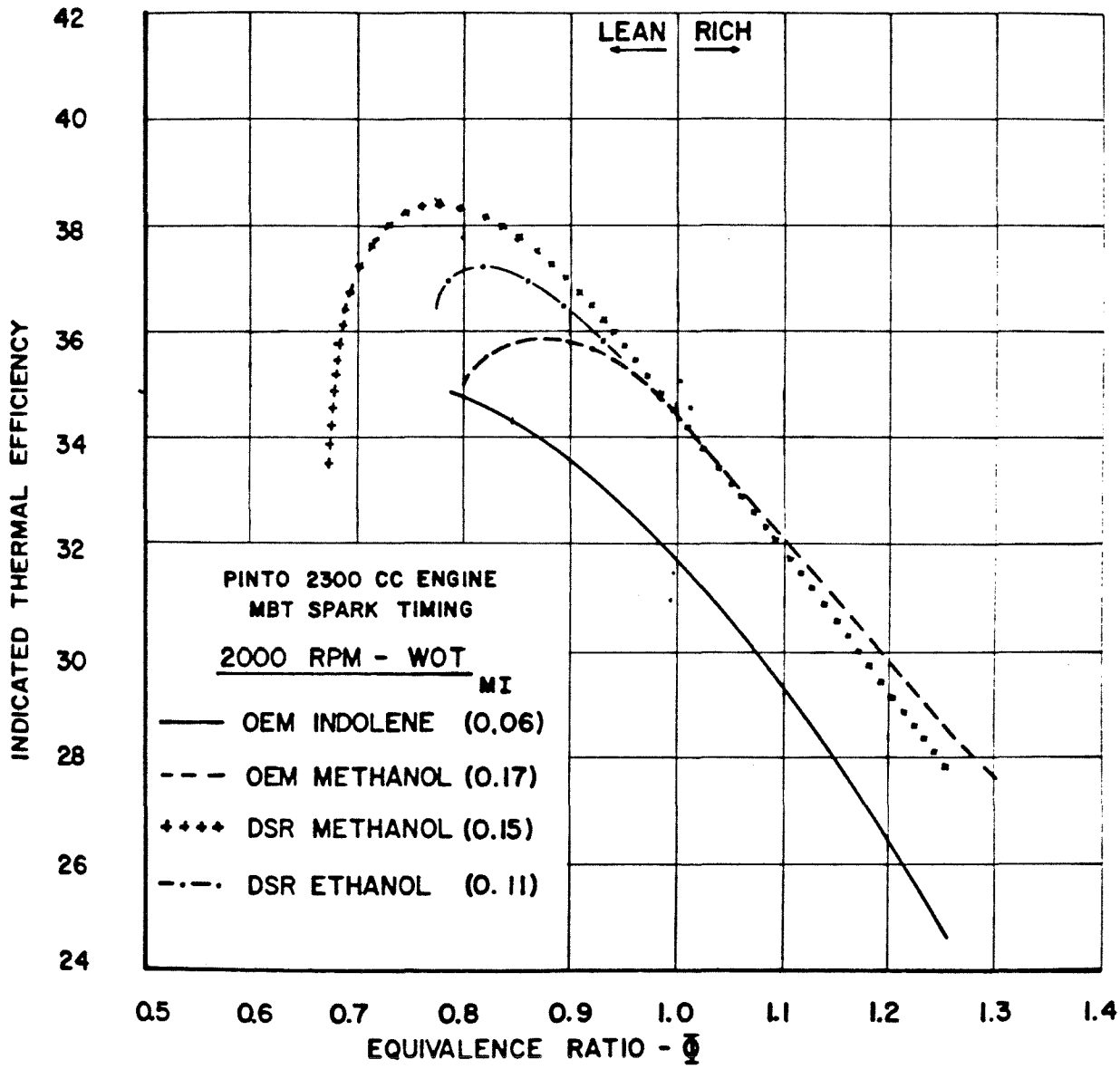


Figure 8-22. COMPARISON OF INDUSTRIAL THERMAL EFFICIENCY FOR SEVERAL ENGINE INDUCTION SYSTEMS (Ref. 5).

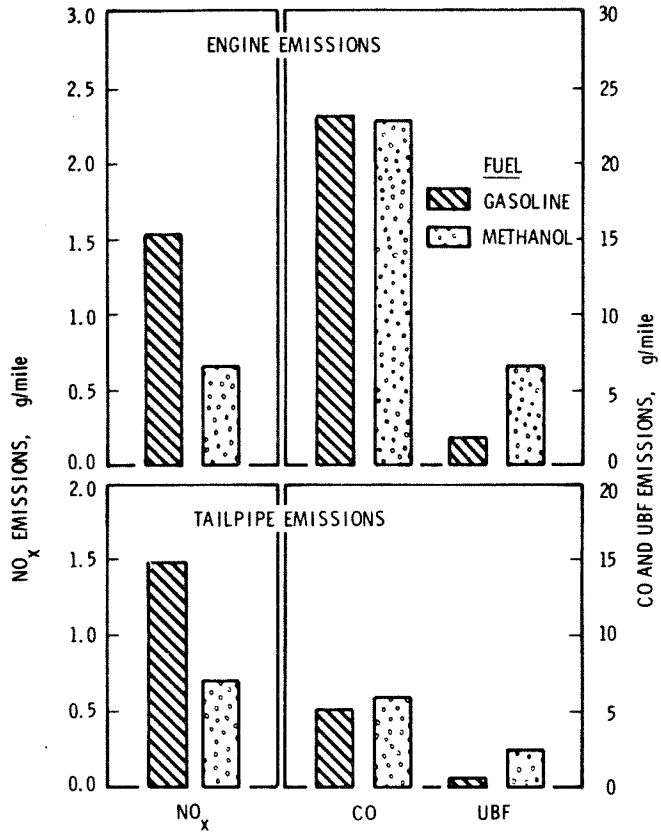


Figure 8-23. COMPARISON OF COLD-START DRIVEABILITY WITH GASOLINE AND METHANOL (Ref. 9).

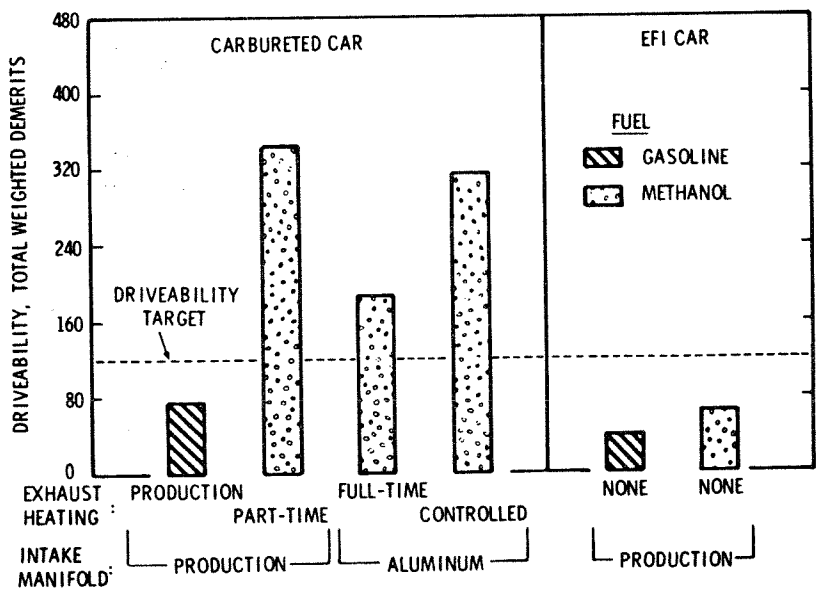


Figure 8-24. EMISSION COMPARISONS FOR GASOLINE AND METHANOL, TWO-WAY EXHAUST CATALYST (Ref. 9).

c. Fuel Economy. The fuel economy results are presented in Figure 8-25, both on a volumetric and energy basis. As expected, the volume-based economy (miles/gallon) of methanol was about one-half that of gasoline. On an energy basis (miles/10^6 Btu), however, the methanol fuel economy was better than that obtained using gasoline. This improvement can be explained on the basis of reduced heat loss to the coolant, increased volumetric efficiency and engine operation closer to the best-power spark advance when using methanol as the fuel.

d. Effect of Spark Advance and Equivalence Ratio. Additional tests were run on methanol with the EFI car to determine the tradeoffs in emissions, driveability, and fuel economy by varying both the spark advance and operating equivalence ratio. The results of Figure 8-26 show that the methanol fuel mixture can be leaned to 0.83 equivalence (with best-power spark timing) before driveability is considered as unacceptable. The emission levels are given in Figure 8-27; Figure 8-28 shows the fuel economy results for methanol in the EFI-equipped car. The maximum economy is seen to occur near the 0.83 equivalence ratio operating range.

No single value of equivalence ratio and spark timing was found to simultaneously provide the best driveability and lowest emissions and fuel consumption. Considering the 1977 EPA emission standards, an equivalence ratio of 0.83 and best-power spark advance was considered as acceptable. This operating point also corresponds to best fuel economy.

With retarded spark timing, a NO_x level of 0.4 g/mile was achieved at this same equivalence ratio. The effect of spark retard on emissions, driveability, and fuel economy is shown in Figure 8-29.

6. California Fleet Test Experience with Neat Methanol Vehicles

Although not common, neat methanol vehicles are not unknown to California. In addition to a small number of methanol conversions owned by individuals, both the California Energy Commission and the Bank of America are involved in major fleet tests. The Bank of America has converted a number of late-model General Motors cars to operate on neat methanol. The results reported to date appear favorable, however, good documentation on the Bank of America fleet tests is not yet available in the open literature. The California Energy Commission has been conducting a multi-phase, well documented fleet-test program (Ref. 10). The CEC fleet-test program is composed of three different fleets: Fleet One was composed of 12 vehicles, four using gasoline as controls, four using methanol, and four using ethanol; Fleet Two is composed of 50 1981 VW Rabbits of which 39 were designed and manufactured by VW to operate on methanol or ethanol, and the remaining 11 are gasoline-control vehicles; Fleet Three is composed of 55 1981 Ford Escort stationwagons. Unlike fleets one and two, which also tested ethanol, fleet three is focused on only neat methanol.

In Fleet One there are four neat methanol vehicles - two with high-compression engines and two with standard-compression engines. The exhuast and evaporative emissions from the Fleet One vehicles are shown in

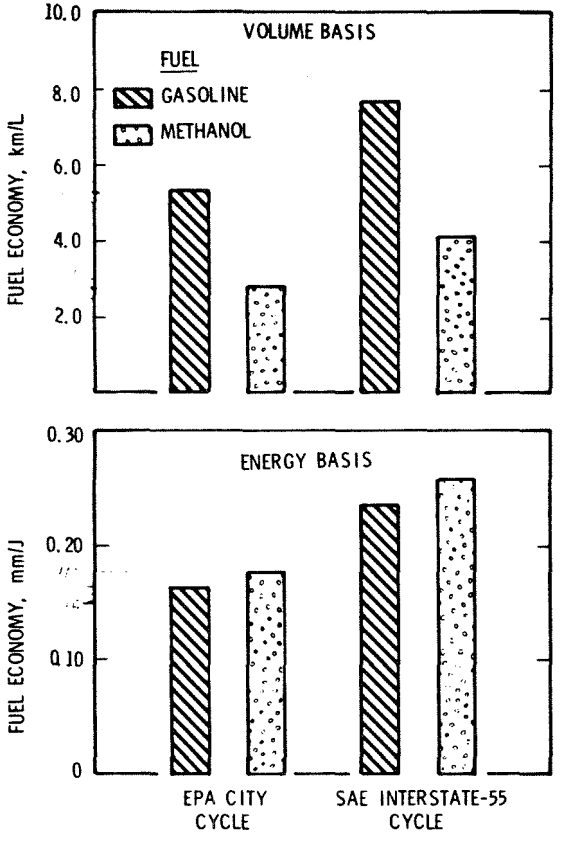


Figure 8-25. FUEL ECONOMY COMPARISONS FOR GASOLINE AND METHANOL (Ref. 8)

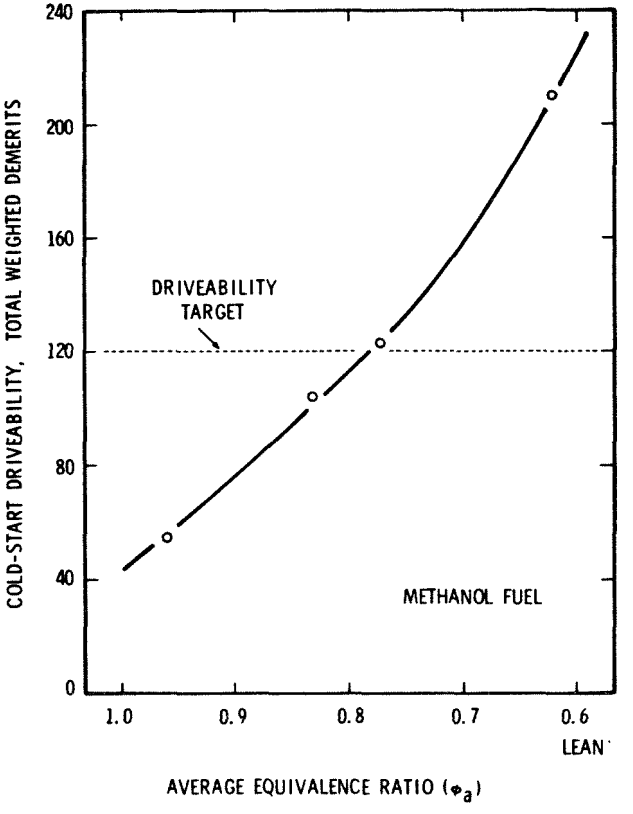


Figure 8-26. EFFECT OF EQUIVALENCE RATIOS ON COLD-START DRIVEABILITY (Ref. 8)

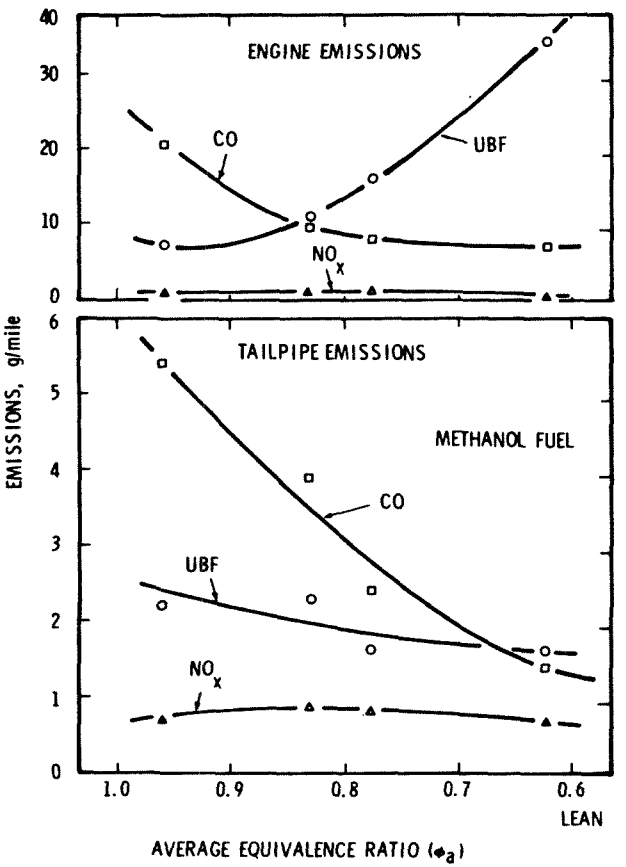


Figure 8-27. EFFECT OF EQUIVALENCE RATIO ON EXHAUST EMISSIONS (Ref. 8)

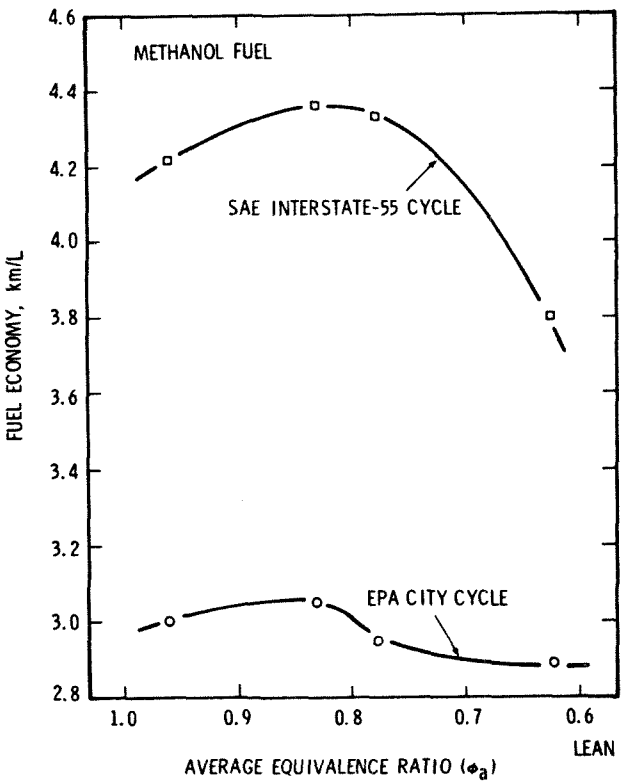


Figure 8-28. EFFECT OF EQUIVALENCE RATIO ON FUEL ECONOMY (Ref. 8)

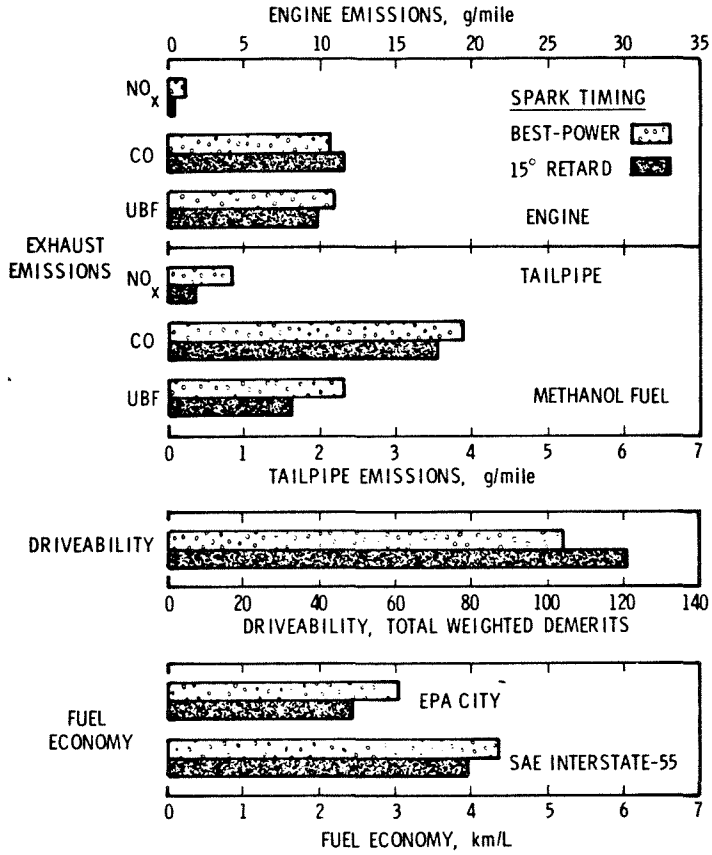


Figure 8-29. EFFECT OF RETARDING SPARK TIMING ON EXHAUST EMISSIONS, DRIVEABILITY AND FUEL ECONOMY (Ref. 9).

Table 8-10, and the fuel efficiency is presented in Table 8-11. Fleet One demonstrated that, if required, it is feasible to convert existing vehicles to neat methanol (or ethanol) and at the same time maintain emission standards (in this case the 1980 California standard).

Table 8-10. EXHAUST AND EVAPORATIVE EMISSIONS TEST RESULTS FOR FLEET ONE PINTOS

	EMISSIONS			
	Grams/Mile			EVAPORATIVE HC (Grams/Test)*
	HC	CO	NO_x	
1980 CA STD	0.40	9.0	1.00	2.0
METHANOL PINTO	0.16	2.0	0.72	1.3
GASOLINE PINTO**	0.40	6.5	0.75	0.7

*SHED Test
**1980 California Pinto Certification Vehicle

SOURCE: "Senate Bill 620: Alcohol Fleet Test Program," California Energy Commission Staff Report, December 1981 (P500-82-003)

Table 8-11. CITY DRIVING CYCLE AND PRELIMINARY ON-ROAD FUEL ECONOMY RESULTS FOR FLEET ONE PINTOS (Miles per gallon/gasoline equivalent)

VEHICLE	CITY DRIVING CYCLE	ON-ROAD (Average)
Gasoline	16.8	20.6
Low Compression Ethanol	18.2	19.8
Low Compression Methanol	18.1	18.6
High Compression Ethanol	19.5	21.0
High Compression Methanol	19.0	22.4

SOURCE: "Senate Bill 620: Alcohol Fleet Test Program," California Energy Commission Staff Report, December 1981 (P500-82-003)

Fleet Two consists of 50 VW Rabbits of which 19 were designed and manufactured by VW for methanol and 20 for ethanol. Table 8-12 shows the performance and driveability test results for the methanol and ethanol Rabbits in comparison to a 1980 gasoline model. Although the results of Fleet Two's fuel economy test are not yet published, the methanol-prototype test results have been published. These are presented in Table 8-13. The methanol Rabbit showed approximately 6% fuel efficiency advantage over the gasoline vehicle, although it was estimated to have 20% more power. As was the case with fuel economy, only the prototypes were available for exhaust and evaporative emission tests. The preliminary test results on the prototype are shown in Table 8-14.

Fleet Two demonstrated the feasibility of producing methanol (or ethanol) vehicles on a domestic assembly line. Fleet Two also has demonstrated that the California emission standards can be met with methanol vehicles while equaling or surpassing gasoline energy efficiency, performance, and driveability.

Fleet Three consists of 40 Ford Motor Company-designed neat methanol Escorts and 15 gasoline-control vehicles. The Fleet Three vehicles will be incorporated into the everyday service of LA County Fleet. The preliminary results for fuel economy and emissions are shown in Tables 8-15 and 8-16. In addition to confirming the results of Fleet Two, Fleet Three will demonstrate the practicality of integrating methanol vehicles into the day-to-day operations of large government fleets. A new report by the California Energy Commission should become available in early 1983, updating the results of the Fleet Three test program.

7. Methanol Automobiles Versus Conventional Gasoline Baseline Automobiles

It is commonly believed that the systemic problem for the potential use of methanol in automobiles is the establishment of a retail methanol distribution system. Underlying this belief is the assumption that if such a retail distribution system existed, methanol fueled vehicles would at least be over-the-road cost competitive with gasoline fueled vehicles. A further belief is that these vehicles could possibly market dominate the gasoline vehicles due to future security of supply of imported petroleum versus domestic coal. Since these assumptions are based upon presumed future conditions, they can neither be fully verified nor refuted. The assumptions can, however, be examined in more detail to determine if their bases appear reasonable. A brief quantitative analysis was performed to examine the viability of methanol fueled vehicles under the assumption of the existence of a retail distribution system. An evolving conventional gasoline fueled vehicle baseline was assumed. This moving baseline spans 1982 to 1997. Based upon existing data for methanol cars, a methanol fuel competitor was developed and compared to this baseline. These comparisons were made for over-the-road energy efficiency and user fuel cost.

Table 8-12. VEHICLE DRIVEABILITY AND PERFORMANCE DATA

	1.6L METHANOL +5.5% ISOPENTANE	1.6L ETHANOL	1.6L 1980 PRODUCTION GASOLINE MODEL
DRIVEABILITY			
Crowds (0 - 50 MPH with constant intake vacumn)	8	8	7
Road Loads (25 - 60 mph)	8	8	8
Wide open throttle acceleration (0 - 60 mph)	7	7	7
Part Throttles Acceleration (0 - 50 mph)	8	8	7
Warm Idle Quality (in gear)	6	4.5*	6
Tips Ins (0 - 30 mph) Opening throttle to 1/4 to 1/2 throttle	7	7	7
PERFORMANCE			
Accels. Sec. (0 - 40 mph)	7.2	7.4	7.5
Accels. Sec. (0 - 60 mph)	15.0	15.6	16.1
REFERENCE INFORMATION			
Vehicle Weight (lb)	1285	1286	2163
Temperature ^{o}F	39	79	41
Humidity %	89	69	55
Barometer in. Hg.	29.86	29.69	30.10

*Engine is new; idle will improve with mileage.

SOURCE: "Senate Bill 620: Alcohol Fleet Test Program," California Energy Commission Staff Report, December 1981 (P500-82-003)

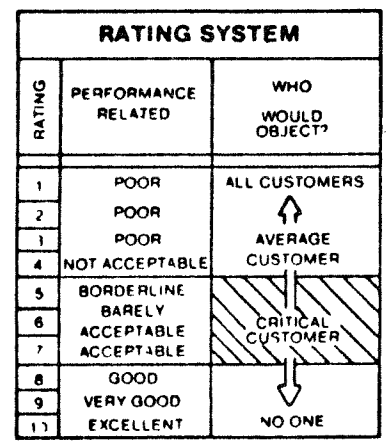


Table 8-13. PROTOTYPE VOLKSWAGEN OF AMERICA RABBIT FUEL ECONOMY RESULTS
(Miles per gallon/gasoline equivalent)

	1985 CORPORATE AVERAGE FUEL ECONOMY (Program Goal)	METHANOL RABBIT (low mileage testing)	ETHANOL RABBIT (low mileage testing)	GASOLINE (1981 Calif. certification)
City Driving Cycle	-	26	24.6	24.4
Highway Driving Cycle	-	3.4	29.9	32.1
Combined City and Highway Driving Cycle	27.5	29.1	26.7	27.4

SOURCE: "Senate Bill 620: Alcohol Fleet Test Program," California Energy Commission Staff Report, December 1981 (P500-82-003)

Table 8-14. VWoA PROTOTYPE RABBIT EMISSION TEST RESULTS COMPARED WITH THE PROGRAM GOALS AND GASOLINE RABBIT TEST RESULTS

		EMISSIONS			
		Grams/Mile			EVAPORATIVE HC (Grams/Test)*
		HC	CO	NO_x	
1982 STD PROGRAM GOAL		0.40	7.0	0.70	2.0
1982 CA OPT PROGRAM GOAL		-	-	0.40	-
METHANOL PROTOTYPE RABBIT	HIGH	0.17	1.2	0.39	-
	MEAN	0.12	0.7	0.31	1.5
	LOW	0.09	0.5	0.18	-
GASOLINE RABBIT**		0.15	1.7	0.30	1.4

*SHED Test
**1981 California Gasoline Rabbit

SOURCE: "Senate Bill 620: Alcohol Fleet Test Program," California Energy Commission Staff Report, December 1981 (P500-82-003)

Table 8-15. METHANOL PROTOTYPE AND GASOLINE FORD ESCORT FUEL ECONOMY RESULTS
(Miles per gallon/gasoline equivalent

	1985 CORPORATE AVERAGE FUEL ECONOMY	METHANOL PROTOTYPE ESCORT	GASOLINE CERTIFICATION
City Driving Cycle	-	24.1	24.4
Highway Driving Cycle	-	37.2	34.3
On-Road (Average)	-	30.0*	28.1**
Combined City and Highway Driving Cycle	27.5	28.6	28.0

*Three production vehicles.
**Control vehicles

SOURCE: "Senate Bill 620: Alcohol Fleet Test Program," California Energy Commission Staff Report, December 1981 (P500-82-003)

Table 8-16. EXHAUST AND EVAPORATIVE EMISSION TEST RESULTS FOR FLEET THREE PROTOTYPE VEHICLE

	EMISSIONS			
	Grams/Mile			EVAPORATIVE HC (Grams/Test)*
	HC	CO	NO_x	
1982 CA STD PROGRAM GOAL	0.40	7.0	0.40	2.0
1982 OPT. CA STD	-	-	0.70	-
METHANOL ESCORT	0.16	3.82	0.33	**
GASOLINE ESCORT***	0.22	5.5	0.60	1.5

*SHED Test
**Not yet tested.
***1981 California Gasoline Escort

SOURCE: "Senate Bill 620: Alcohol Fleet Test Program," California Energy Commission Staff Report, December 1981 (P500-82-003)

a. The 1982 - 1997 Conventional Gasoline Baseline. For methanol to be viable as a transportation fuel, methanol car sales must be, for a large part, within the "middle of the market." It is assumed that a five passenger sedan will continue to be representative of the middle of the market through 1997. On the supply side of a methanol fuel system, to justify one large coal-based plant on neat methanol fuel solely on the existence of neat methanol automotive fuel would require the existence of approximately 300,000 methanol fueled automobiles. Downstream, at the point of retail sales, to justify investments in new tanks and pumps, roughly 10 to maybe 15 percent of a retail outlet's sales volume would have to be in methanol. At long run equilibrium this would imply 10 to 15 percent of new car sales would have to be methanol fueled vehicles. It would be difficult to establish such sales volumes through specialty cars alone. Therefore, comparisons of future methanol fueled vehicles to conventional gasoline fueled vehicles will be made for a presumed middle-of-the-market car. A smaller mid-sized five passenger sedan, which in 1982 was approximately 2,450 pounds curb weight and had a city fuel efficiency of approximately 26 mpg was chosen as the benchmark vehicle. This vehicle will then be projected through 1997. While not a specific 1982 vehicle, this benchmark can be viewed as being similar to current GMX bodies such as a Citation or an 1982 Chrysler K-series car such as the Aries.

The vehicles being sold 15 to 20 years in the future will be the result of complex workings of markets, prices, technology developments, and other factors. This analysis does not presume to make a detailed forecast of these factors and any statement about such future conditions can be viewed as an assumption at best. The presumed changes will be divided into three categories: 1) overall vehicle weight reduction, 2) non-engine related vehicle changes, and 3) changes in conventional engine technology. Some of these changes in the baseline gasoline vehicle can directly affect the energy efficiency difference between the gasoline vehicle and the methanol vehicle. Some of the assumed future changes in the baseline vehicle would also include the over-the-road efficiency of the methanol vehicle. These changes include vehicle weight reduction, drive line efficiency improvements, aerodynamic improvements, etc. Some of the engine improvements would also improve the efficiency of the methanol vehicle, such as more accurate computer control of the ignition and fuel system. Since a methanol fueled vehicle derives its efficiency advantage over a gasoline vehicle from three basic areas: increased compression ratio, leaner misfire limit permitting leaner average part-load operations, and higher heat evaporation, changes to the conventional vehicle in these areas would reduce the efficiency advantage of the methanol vehicle. For example, if the compression ratio of future gasoline fueled vehicles is higher, the efficiency advantage of the higher compression ratio methanol vehicle would be somewhat eroded. On the other hand, efficiency gained through reduced accessory loads would be as applicable to the methanol vehicle as to the baseline vehicle and hence the efficiency advantage of the methanol fueled vehicle would not be eroded. For estimating the future efficiency advantages for methanol fueled vehicles, the type of changes that occur to the conventional baseline is as important as the effect of the changes on the baseline fuel efficiency.

Reasonably smooth evolutionary change has been assumed. In fact, many technical changes are steplike. For example, basic chassis weight may stay almost constant for several years, then decrease significantly upon the introduction of a new design. Likewise, if efficiency is improved by using a leaner part-load mixture, the change from near stoichiometric three-way to lean burn/fast burn is stepwise, not evolutionary. Because the timing of such changes and how pervasive the changes may be are not well known, the assumed changes have been "smoothed out" over the period 1982 to 1997.

Modest decreases in vehicle weights between 1982 and 1997 have been assumed. For the weight reduction of the baseline vehicles, a 6 percent total vehicle curb weight reduction in ten years will be assumed. This results in the baseline vehicle curb weight decreasing from 2450 pounds in 1982 to approximately 2300 pounds in 1997. It should be noted that in the three years between 1978 and 1981 the average curb weight for mid-sized vehicles sold in the United States decreased by 9 percent (Ref. 37). To the extent that past developments are a guide to future events, the assumed future weight reduction could be overly conservative.

To express changes other than vehicle weight reduction the product of mpg and inertial weight will be used. For the baseline 1982 vehicle this product was approximately 31 inertial ton miles per gallon. The assumed changes in the mpg inertial weight product are given in Table 8-17.

Between 1982 and 1987, this assumption implies a change of approximately 2-1/2 percent per year for the fuel economy of our baseline vehicle independent of weight reduction. In terms of past history, between 1978 and 1979, 3 percent of the corporate average fuel economy for General Motors cars was attributable to technological changes within a vehicle class other than weight reduction (Ref. 37). The same factor for 1979 to 1980 was 3 percent, and between 1980 and 1981 was 7 percent. For the period of 1981 to 1986, Dowdy (Conventional Engine Technology, Vol. III, Comparisons and Future Potentials, Ref. 38) projected a 10 percent improvement for uniform charge three-way catalyzed engine technology, a 15 percent improvement for lean or fast burn technology, and a 21 percent improvement if there was a shift from 1981 uniform charge engines to lean burn/fast burn engines by 1986 as shown in Figure 8-30. Heywood (Automotive Engines and Fuels: A Review of Future Options (Ref. 39) is considerably more optimistic projecting up to a 50 percent improvement over the next ten years.

Table 8-17. BASELINE PERCENT IMPROVEMENT RELATIVE TO 1982

YEAR	mpg X IW	VEHICLE, DRIVE, AND ENGINE (%)	ENGINE ONLY (%)
1982	31.0	-	-
1987	35.0	12.5	10
1992	37.4	20.5	16
1997	40.1	29.5	25

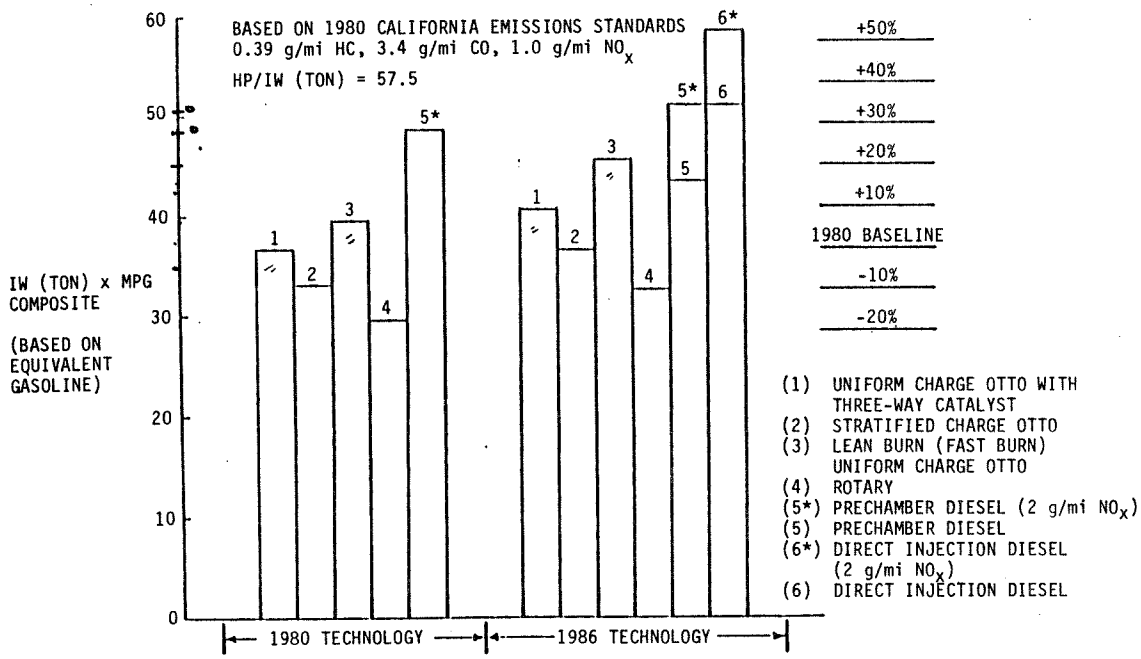


Figure 8-30. FUEL ECONOMY EXPECTATION FOR 1986

For the 1987 vehicle the 10 percent assumption in engine brake efficiency improvement is a result of three factors: 1) a compression ratio increase from 9:1 to 10:1 resulting in a 2 to 3 percent efficiency improvement, 2) slightly leaner part load operations, such that the average equivalancy ratio is reduced by approximately 0.04 to 0.05 which results in approximately a 2 to 3 percent improvement, and 3) a 4 to 6 percent improvement resulting from all other engine changes such as accessory load reduction, fuel ignition computed control, etc.

For the 1992 baseline the brake thermal efficiency of the engine was presumed to have been improved over the 1982 engine by approximately 16 percent. The 16 percent improvement is decomposed into approximately 4 percent from the compression ratio being increased to approximately 11:1, approximately 4 percent from the average equivalency ratio for the engine being reduced by about 0.06 and 8 percent from all other effects.

For the 1997 conventional baseline an efficiency improvement of 25 percent in brake thermal efficiency over the 1982 baseline was assumed. This

efficiency improvement is probably more consistent with the direct injected stratified charge gasoline technology than it is with a continued evolution of the baseline engine. Relative to the 1982 baseline approximately 6 percent of the improvement is attributable to an assumed 12.5:1 compression ratio, 9 percent from mixture leaning and 10 percent from all other effects.

The weight independent technology improvements relative to the 1982 baseline are summarized in Table 8-18. Two implicit assumptions about the evolution of the conventional vehicle baseline have also been made. The first is that fuel efficiency has not been gained by significantly decreasing the horsepower to weight ratio of the vehicle. The 1982 vehicle has a horsepower to curb weight ratio of approximately 0.030 horsepower per curb weight pound. The second implicit assumption is that the fuel tank range for the vehicle does not change appreciably. For the 1982 vehicle this was approximately 300 to 350 miles (city driving). While the assumed range does not directly affect the baseline (apart from a very slight contribution to total vehicle weight reduction as mpg increases) it will have a small impact on the methanol vehicle due to gasoline methanol fuel factor being approximately 1.7 to 1.8 combined with a slightly greater density (pounds per gallon) for methanol fuel.

The results of these assumptions are summarized in Table 8-19. Under the above assumptions the fuel economy for the baseline vehicle evolves from 26 mpg in 1982 to 40.2 by 1997. Vehicle curb weight decreases from 2450 pounds in 1982 to 2300 pounds in 1997. As explained above, the assumed improvement in the conventional baseline is more conservative than other recent projections. However, under the baseline gasoline price scenario it does result in a significant decrease in over-the-road fuel expenses until approximately 1990. The real over-the-road fuel expenses do not again rise to the 1982 level until approximately 1997. The over-the-road fuel expenses which are the combination of the fuel price forecast and the above technology assumptions are presented in Figure 8-31.

b. Methanol Vehicles. For each point on the conventional vehicle baseline, a methanol fuel competitor was defined beginning with a 1982 benchmark methanol vehicle.

Although the data from no single source will exactly duplicate the 1982 benchmark methanol vehicle, the assumptions characterizing this vehicle are not inconsistent with current research data and test results such as: Volkswagen (for example, Ref. 6), General Motors (Ref. 26) and State of California (Ref. 10). Additionally, two recent assessments (Refs. 40, 41) reached a similar characterization.

The methanol vehicle technology was presumed to experience improvements similar to that for the gasoline baseline. Hence, the fuel efficiency of both the conventional gasoline vehicle and the methanol vehicle are assumed to be improving between 1982 and 1997, but not at the same rate or by the same means. The result of this probable improvement will be a modest change in the energy efficiency advantage of the methanol fueled vehicle.

As has been discussed in previous sections, methanol fueled vehicles would be expected to have somewhat higher energy efficiency than gasoline fueled vehicles and test results have for the most part confirmed that

Table 8-18. CHANGES FROM 1982 BASELINE FOR CONVENTIONAL GASOLINE TECHNOLOGY

1987 12.5% improvement over 1982 baseline (mpg x inertial weight)

- 1.0% in non-weight vehicle changes
- 1.5% in market shift towards manual transmission (and/or technical improvement to driveline efficiency)
- 10% in engine brake efficiency:
  - 2-3% from CR 9:1 to 10:1
  - 2-3% from lean burn-fast burn, $\Delta\phi \approx 0.04$ to 0.05
  - 6-4% all other engine improvements

1992 20.5% improvement over 1982 baseline (mpg x inertial weight)

- 2.0% in non-weight vehicle changes
- 2.5% drive train
- 16% in engine brake efficiency
  - 4% from CR 9:1 to 11:1
  - 4% leaning $\Delta\phi \approx 0.06$
  - 8% all other engine improvements

1997 29.5% improvements over 1982 baseline

- 2.0 in non-weight vehicle changes
- 2.5% drive train
- 25% in engine brake efficiency
  - 6% from CR of 12.5:1
  - 9% leaning $\Delta\phi \approx 0.10 - 0.15$
  - 10% all other engine improvements

Table 8-19. CONVENTIONAL GASOLINE BASELINE

YEAR	CURB WEIGHT	FUEL EFFICIENCY (mpg city)	FUEL COSTS (1981 ¢/mile)	
			BASELINE PRICE SCENARIO	MED-HIGH PRICE SCENARIO
1982	2450	26.0	4.70	4.70
1987	2400	33.5	3.79	4.23
1992	2350	36.6	4.46	5.79
1997	2300	40.2	4.70	6.17

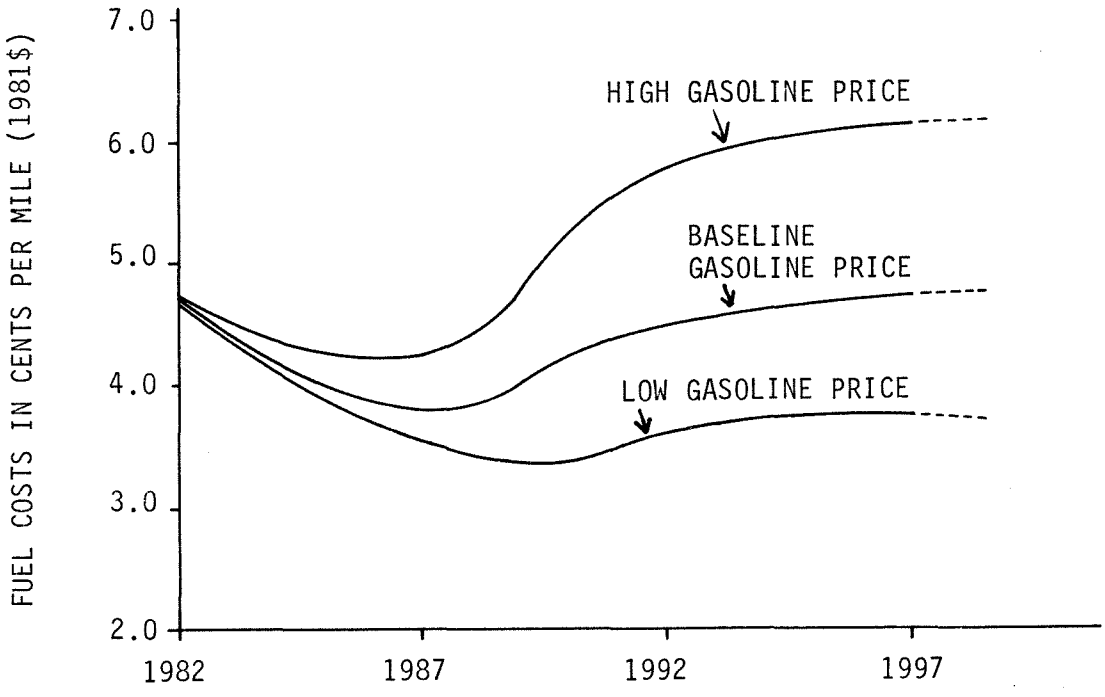


Figure 8-31. BASELINE VEHICLE VARIABLE FUEL COSTS

expectation. This efficiency advantage can be conceived as being derived from three effects:

(1) A higher effective octane number than gasoline permitting higher and hence more efficient engine compression ratios.

(2) A leaner misfire limit permitting leaner part load operations than gasoline.

(3) An effect related to the higher heat of vaporizaton of methanol which reduces the heat transfer to the coolant and/or increases the volumetric efficiency of the engine.

The actual efficiency advantage of a methanol vehicle cannot be exactly specified since it is design dependent. However, based upon published results of engine and vehicle research and testing, a range for the efficiency improvement can be estimated.

In principle, an increase in the compression ratio of an engine will increase its indicated thermal efficiency. Based on a fuel air cycle analysis, the increase in indicated efficiency can be readily calculated. However, increasing the compression ratio on a real engine may not produce as large an increase in brake thermal efficiency. The brake efficiency increase will be less, due principally to mechanic/frictional loss increases due to the higher mean effective pressure. Table 8-20 presents the assumptions on compression ratio increase and the increase in brake efficiency for the methanol and gasoline baseline. The gasoline baseline slowly evolves from 9:1 to between 11:1 and 13:1 by 1997. This results in approximately a 4 to 7 percent increase in efficiency. The 1982 methanol vehicle is assumed to have a compression ratio of approximately 12:1 and to evolve to approximately 14:1 by

Table 8-20. COMPRESSION RATIO ASSUMPTIONS

YEAR	GASOLINE		METHANOL		% EFFICIENCY ADVANTAGE OF METHANOL VEHICLE IN GIVEN YEAR DUE TO CR DIFFERENCES
	CR	% IMPROVEMENTS OVER 1982 IN BRAKE THERMAL EFFICIENCY	CR	% IMPROVEMENTS OVER 1982 GASOLINE BRAKE THERMAL EFFICIENCY	
1982	9:1	-	12:1	5	5
1987	10:1	2	12:1-14:1	5 - 8	3 - 6
1992	11:1	4	13:1-	7 - 8	3 - 4
1997	11:1-13:1	4 - 7	14:1	8	1 - 4

1997. This results in an approximately 3% increase in the methanol engine's efficiency, and thus in a slow erosion of the advantage due to compression ratio increase of the methanol vehicle compared to the gasoline vehicle.

An increase in the compression ratio of an engine can promote an increase in the NO_x emissions. Some actions taken to reduce this increase in NO_x can significantly erode the efficiency gained by increasing the compression ratio. It has been assumed that if the baseline gasoline vehicle compression ratio increase can be effected while maintaining emission standards, then the methanol engine can also meet such standards at the higher compression ratios.

If the fuel air ratio can be reduced while maintaining acceptable combustion, the thermal efficiency of an engine can be increased. For both gasoline and methanol, if the part load lean limit is decreased by approximately 5 percent the thermal efficiency will be improved by approximately 3 percent. However, beyond approximately 15% lean, over-the-road fuel efficiency for methanol vehicles has found not to increase significantly and in some cases to decrease. This effect has been reported both by Pefley and by Brinkman (Ref. 24,42). If the 1982 baseline conventional vehicle is operating with a part load equivalency ratio in the range of 0.96 to 1.0, this implies a methanol vehicle operating at a part load equivalency ratio of about 0.85 would be approximately 5 - 7% more efficient.

When methanol is burned in an engine rather than gasoline with no change of compression ratio or equivalency ratio, a thermal efficiency improvement of approximately 6 - 8% has been observed. This increase in efficiency has been attributed to various factors but is probably related to the increased heat of vaporization of methanol in comparison to gasoline.

Table 8-21 presents the possible improvement in energy efficiency for the methanol vehicle in comparison to the moving gasoline baseline for 1982 - 1997. These results indicate that if methanol cars were produced in 1982, they would have approximately an 18% efficiency advantage over gasoline vehicles. However, under the assumptions of improvements in the conventional gasoline powered vehicles, this advantage is slowly reduced to approximately 10% by 1997.

The ratio of gallons of methanol to gallons of gasoline that the same vehicle would consume in travelling the same distance is the fuel factor. The fuel factor is defined as:

$$\frac{h_{gasoline}}{h_{methanol}} \cdot \frac{\eta_{gasoline}}{\eta_{methanol}}$$

where, h is the volumetric energy content of the fuel and is the brake thermal efficiency of the engine. In terms of the previously discussed brake efficiency improvement of a methanol engine versus a gasoline engine, the fuel factor can be expressed as follows:

$$\text{fuel factor} = \frac{2.04}{1 + \text{fractional improvement in thermal efficiency}}$$

Table 8-21. METHANOL EFFICIENCY COMPARED TO GASOLINE BASELINE

YEAR	IMPROVEMENTS IN EFFICIENCY OVER MOVING BASELINE GASOLINE VEHICLE DUE TO:			RANGE OF IMPROVEMENT	BEST GUESS	METHANOL-GASOLINE FUEL FACTOR	
	INCREASED COMPRESSION RATION	LEANER AVERAGE MIXTURE	METHANOL HEAT OF VAPORIZATION			RANGE	BEST GUESS
1982	4 - 6%	5 - 7%	6 - 8%	15 - 21%	(18.0)%	1.77-1.69	(1.73)
1987	3 - 6%	2 - 4%	6 - 8%	11 - 18%	(14.5)%	1.84-1.73	(1.78)
1992	3 - 4%	1 - 2%	6 - 8%	10 - 14%	(12.0)%	1.85-1.79	(1.82)
1997	1 - 4%	--about	(6 - 9%)--	7 - 13%	(10.0)%	1.91-1.80	(1.86)

For example, a 20% improvement in brake thermal efficiency would result in a fuel factor for methanol versus gasoline of 1.70. If a gasoline vehicle used one gallon of gasoline in traveling 26 miles, the methanol vehicle would use 1.7 gallons of methanol to travel the same 26 miles. Graphically the relationship between the methanol-to-gasoline fuel factor and the thermal efficiency improvement of methanol versus gasoline is presented in Figure 8-32.

Figure 8-33 presents the methanol gasoline fuel factor based upon the assumed improvements in both the baseline and the methanol vehicles. The curve labeled "Best Guess" represents the fuel factor for the "best guess" on the evolving improvement in methanol versus gasoline. The gray area about the line is the possible range for the fuel factor based upon the range for thermal efficiency improvement. For the best guess case the fuel factor changes from 1.73 in 1982 to 1.86 in 1997. It is possible that technological improvements such as lean burn/fast burn combustion are more easily implemented with methanol than gasoline (due to methanol's ability to sustain leaner combustion). Methanol engine technology is clearly less mature than gasoline technology and, therefore, there may exist many improvements specific to methanol that are not currently apparent. Hence, the possibility that methanol's efficiency advantage may not erode, but will maintain the 15 percent to 21 percent advantage it currently has. This is shown in Figure 8-33 as line labeled "No Change."

When combined with the methanol price forecasts, an estimate of the over-the-road fuel cost in cents per mile for the methanol vehicles can be made. Under the assumption that excise taxes would be proportional to the Btu content, hence approximately half as much on a per gallon basis as gasoline and that all other costs would be equivalent on a cents per gallon basis as gasoline, Table 8-22a and Figure 8-34a present the over-the-road fuel cost "no change" estimates for the methanol vehicles. Table 8-22b and Figure 8-34b show the same results for the "no change" case in which the methanol fuel factor does not erode over time. As can be seen by comparing Figures 8-34a

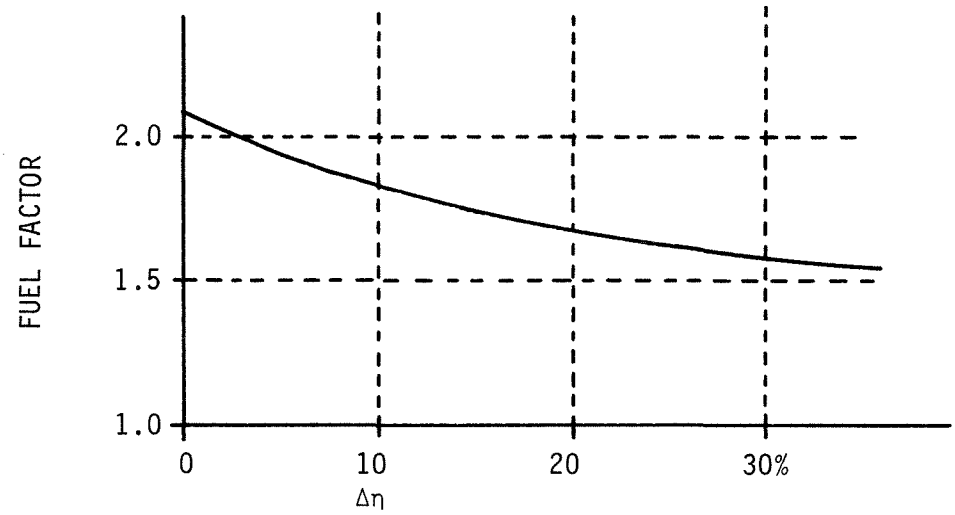


Figure 8-32. METHANOL GASOLINE FUEL FACTOR AS A FUNCTION OF EFFICIENCY IMPROVEMENT

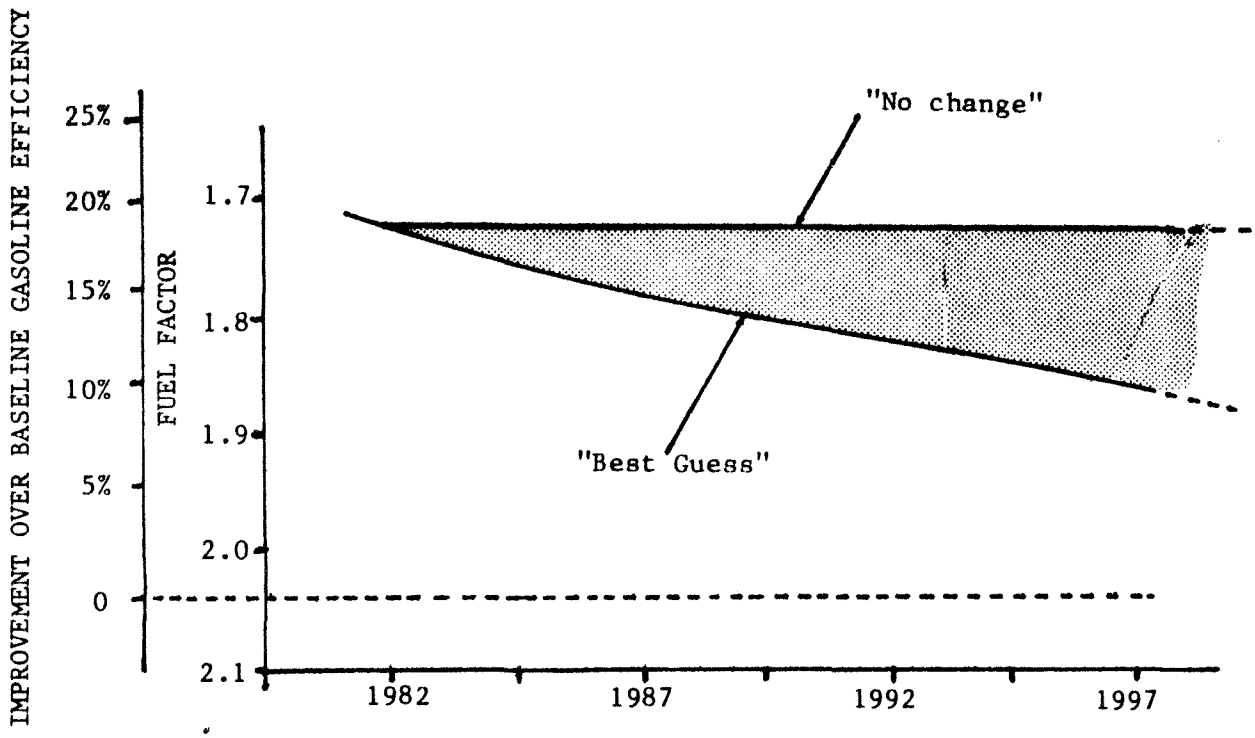


Figure 8-33. METHANOL-GASOLINE FUEL FACTOR 1982-1997

Table 8-22a. OVER-THE-ROAD FUEL COSTS, GASOLINE VERSUS METHANOL ("No Change" Case)

YEAR	EFFICIENCY		COSTS IN CENTS/MILE			
	GASOLINE BASELINE (mpg of Gasoline)	METHANOL (mpg of Methanol)	GASOLINE	REMOTE NATURAL GAS METHANOL	5,000 T/D COAL METHANOL	10,000 T/D COAL METHANOL
1982	26.0	15.0 (14.7-15.4)	4.70	5.97	-	-
1987	33.5	19.3	3.79	4.22	6.71	-
1992	36.6	21.1	4.46	4.01	6.37	5.94
1997	40.2	23.2	4.70	3.80	-	5.68

Table 8-22b. OVER-THE-ROAD FUEL COSTS, GASOLINE VERSUS METHANOL ("Best Guess" Case)

YEAR	EFFICIENCY		COSTS IN CENTS/MILE			
	GASOLINE BASELINE (mpg of Gasoline)	METHANOL (mpg of Methanol)	GASOLINE	REMOTE NATURAL GAS METHANOL	5,000 T/D COAL METHANOL	10,000 T/D COAL METHANOL
1982	26.0	15.0 (14.7-15.4)	4.70	5.97	-	-
1987	33.5	18.8 (18.2-19.4)	3.79	4.34	6.89	-
1992	36.6	20.1 (19.8-20.4)	4.46	4.21	6.69	6.24
1997	40.2	21.6 (21.0-22.3)	4.70	4.07	-	6.10

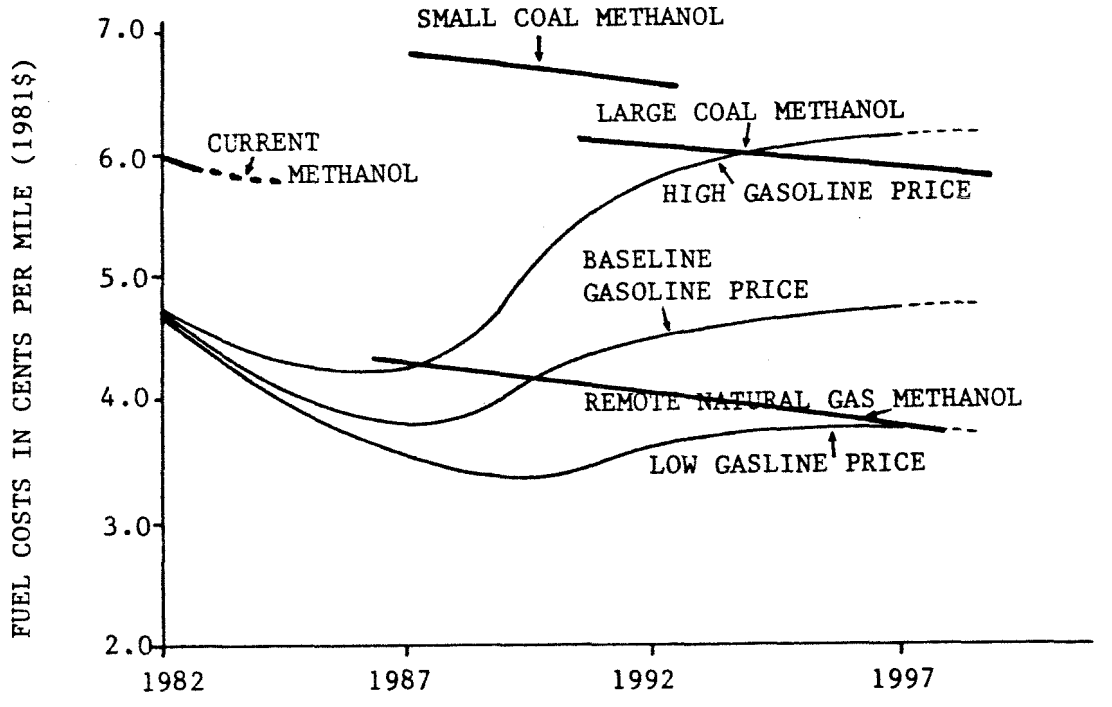


Figure 8-34a. METHANOL VEHICLE VARIABLE FUEL COSTS ("No Change" Case)

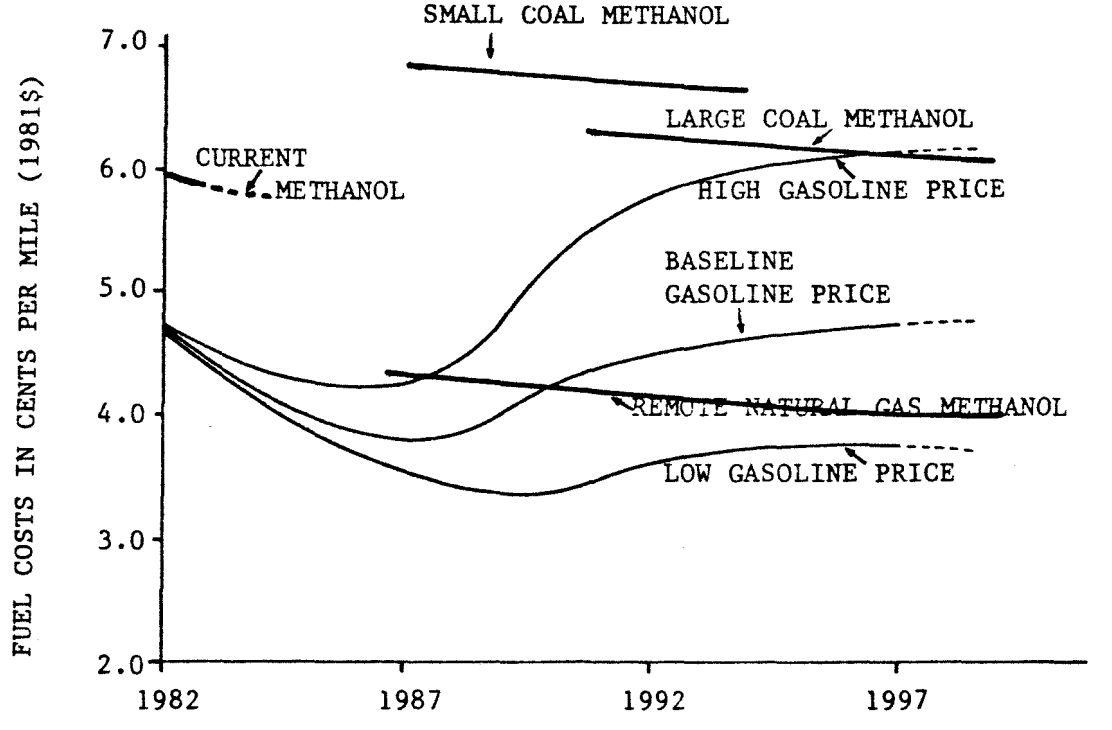


Figure 8-34b. METHANOL VEHICLE VARIABLE FUEL COSTS ("Best Guess" Case)

Table 8-23. RETAIL METHANOL PRICES AT THE PUMP

YEAR	REMOTE NATURAL GAS		5,000 T/D WESTERN COAL		10,000 T/D WESTERN COAL	
	PLANT GATE	RETAIL	PLANT GATE	RETAIL	PLANT GATE	RETAIL
1982		90.0	-	-	-	-
1987	61.0	81.7	96.0	129.5	-	-
1992	63.0	84.6	100.0	134.5	89.0	125.4
1997	65.0	87.8	-	-	94.0	131.8

and 8-34b, the differences between the "best guess" assumption and the "no change" assumption have little impact on the results. The retail prices upon which this is based are presented in Table 8-23. There are two methanol cases, one for a large coal plant, and the other for methanol produced from remote natural gas. A transport cost to the Southern California metropolitan area of 10¢ per gallon for the coal case and 4¢ per gallon for the remote natural gas case were assumed. If the methanol is produced from western coal, methanol cars would become competitive with gasoline cars in approximately the year 2000 if the gasoline price followed the medium high scenario rather than the baseline scenario. If gasoline prices follow baseline scenarios, the coal produced methanol would not be competitive for use in automobiles until considerably past the year 2000.

It should be recognized that this analysis assumes that "over-the road" costs are an adequate surrogate for marketplace competitiveness. In fact, methanol vehicles would have different attributes than gasoline vehicles. It is likely that methanol vehicles could be offered with higher power than their gasoline counterparts as shown by CEC Fleet Two tests. Methanol may be viewed as a more secure fuel by some buyers. To properly evaluate all factors associated with methanol vehicle market viability requires a careful and detailed market survey. It is not clear that potential buyers are sufficiently knowledgeable of methanol vehicles to permit reliable survey results at this time.

As is the case with gasoline-fueled automobiles, methanol-fueled automobiles can be designed and marketed with a wide range of attributes so as to be attractive to various sectors of the market. It should be noted that the benchmark vehicle may not be the one chosen for initial introduction. One specific attribute which may assist the initial introduction of methanol-fueled automobiles is performance. Methanol-fueled engines can be designed to provide higher power than the gasoline-fueled engines. For example, in the 1981 fleet report the California Energy Commission indicated that up to 20% more power was possible. A detailed market survey and analysis would be required to identify the most attractive match of vehicle attributes and market sector for initial methanol-fueled vehicle sales. This is clearly outside the scope of an assessment; however, some indication can be provided on the value of performance and the size of the performance market.

One viewpoint is provided by the comparison of two vehicles which are essentially identical except for performance. Two examples of such vehicle comparisons are the SAAB 900 versus the SAAB 900 Turbo and, the Audi 5000 versus the Audi 5000 Turbo. The SAAB 900 Turbo provided about 20% more power and cost about $3400 more in comparison to the SAAB 900. The 1981 sales of the 900 Turbo were 7377 vehicles nationally, which was 52% of the 900 series sales. The Audi 5000 Turbo provides about 30% more power and costs about $4200 more than the Audi 5000. The 1981 sales of the 5000 Turbo were 5576 vehicles nationally, which was about 19% of the 5000 series sales.

Table 8-24 presents the sale of five domestic performance automobiles. Nationwide 1981 sales were about 175,000 vehicles (about 3% of domestic production about 2% total sales). To the extent that California sales of these specific models reflect California sales across a division (e.g., Pontiac), such as national sales volume would imply about 11,000 of these vehicles sold in California. The performance option for the Chevrolet Camero cost about $2000 above the 4 cyclinder and $450 above the V6 option. The Mustang and Capri V8 cost $1300 and $650 over the respective L4 option.

c. Possible Magnitude of Methanol Demand from Private Passenger Cars. If methanol vehicles do become competitive, a demand for methanol fuel will develop and gasoline demand will be somewhat decreased. The rate and size of the potential growth of fuel methanol will place demands upon the retail infrastructure, and the supply/production capacity. To provide a very approximate estimate of the demand for methanol, several market penetration rates for methanol vehicles were assumed, and the results of the assumed penetration rates in terms of fuel demand have been calculated.

A simplified version of the U.S. Department of Energy's light duty vehicle model was used to perform these calculations. The light duty vehicle model is essentially a fleet replacement model. The basic data and algorithms were maintained, but simplified and adapted for a JPL microcomputer. The results of this calculation should be viewed as indicative rather than conclusive because:

(1) The methanol vehicle market penetration rates were assumed, not calculated.

Table 8-24. HIGH PERFORMANCE DOMESTIC SALES IN 1981

	% SALES OF V8 OPTION	NATIONAL SALES V8 OPTION	ESTIMATED CALIFORNIA SALES OF V8 OPTION
Chevrolet Corvette	100	45,631	2900
Chevrolet Camaro V8	58.8	74,169	4750
Pontiac Firebird V8	66.9	47,459	2450
Ford Mustang V8	3.3	6,025	500
Mercury Capri V8	3.1	1,827	140

(2) The original database for the light duty vehicle model was not recalculated or adjusted for current or future expected market conditions.

Figure 8-35 shows three possible introduction rates for methanol vehicles. These rates are simply assumptions and are not forecasts. The actual rate of introduction would be determined by the realities of the competitive marketplace both in vehicles and in fuels. The moderate growth rate is similar to the growth rate of diesel vehicle sales. Too much reliance should not be placed upon the diesel vehicle sales analog because the attributes of a methanol car will surely be different from that of a diesel car and the market conditions of the early to middle 90's will be different from the market conitions of the late 70's. The high-growth rate introduction assumes that methanol cars are not introduced until there is a marked advantage in over-the-road costs and then within a space of 7 to 8 years methanol car sales grow to 25% of the market. While this is not a maximum upper bound on methanol vehicle sales, there are many factors that inhibit a rapid and complete substitution, such as retooling capacity, amortization of in-place production facilities, and competitive pricing policies of both vehicles and fuel. Likewise, the slow growth rate depicted in Figure 8-35 is not the lowest market penetration that could be envisioned. However, it should be recognized that scale economies for major manufacturers would cause production volumes lower than this to be unattractive.

Figure 8-36 presents the effect that the assumed methanol vehicle sales would ultimately have in the composition of the total vehicle fleet. As can be seen, even with an early and vigorous introduction of methanol vehicles, most of the vehicles on the road in the year 2000 would still be fueled by conventional fuels.

Figure 8-37 presents the impact of the increasing number of methanol vehicles upon the sale of gasoline. (It was presumed that the methanol vehicles would compete principally with the gasoline vehicles. If methanol vehicles were to compete equally with diesel and gasoline vehicles, the same relationship would hold, but then should be viewed as reduction in motor fuel for light duty vehicles.) The increasing demand for methanol motor fuel would require expansion of methanol production capacity. Also depicted in Figure 8-37 is the number of remote natural gas plants that would be necessary to supply the West Coast. The methanol plants referred to in Figure 8-37 are the modest size, 2 to 2-1/2 thousand tons a day remote natural gas plants described in Chapter 4.

8. Advanced Technologies for Methanol Automobiles

Two classes of advanced technologies appear to be appropriate for light-duty methanol applications at this time: direct injected stratified charge (DISC) engines and catalytic dissociation of methanol to hydrogen and carbon monoxide.

DISC technology appears to be more mature than dissociation. However, DISC work to date has not shown significant energy efficiency differences between methanol and gasoline. (It is conceivable that DISC technology is

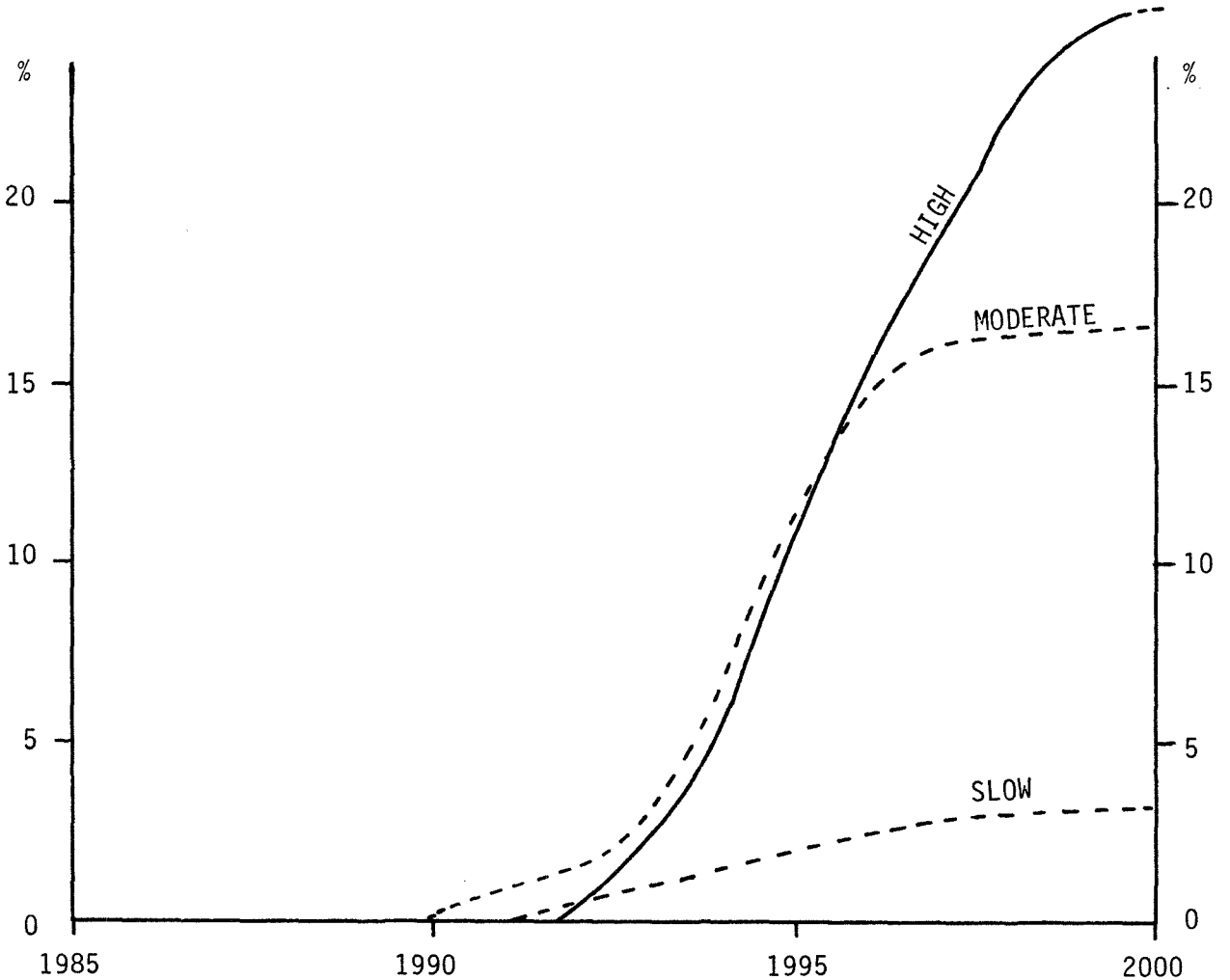


Figure 8-35. METHANOL PERCENT OF NEW CAR SALES (ASSUMED)

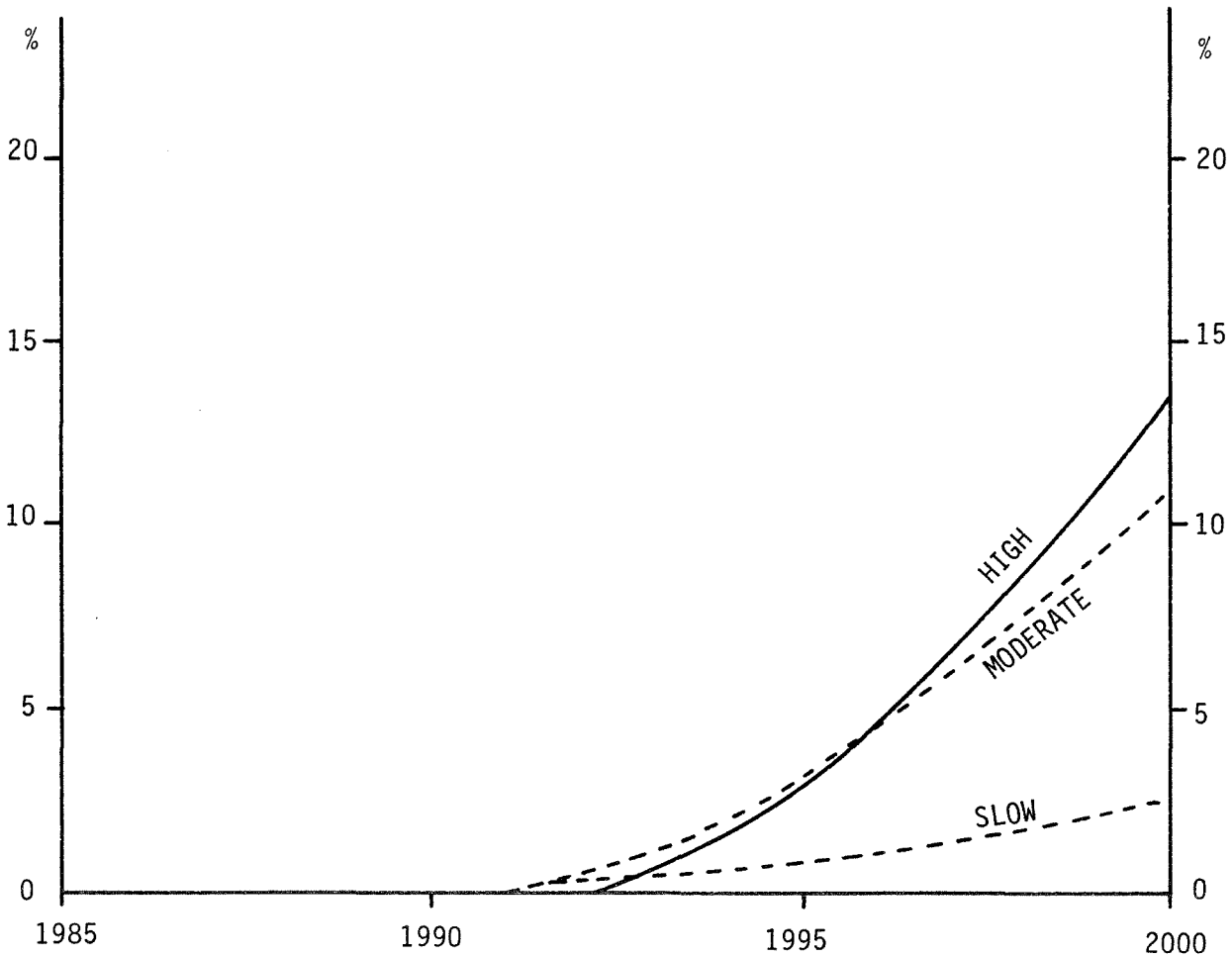


Figure 8-36. METHANOL PERCENT OF TOTAL FLEET

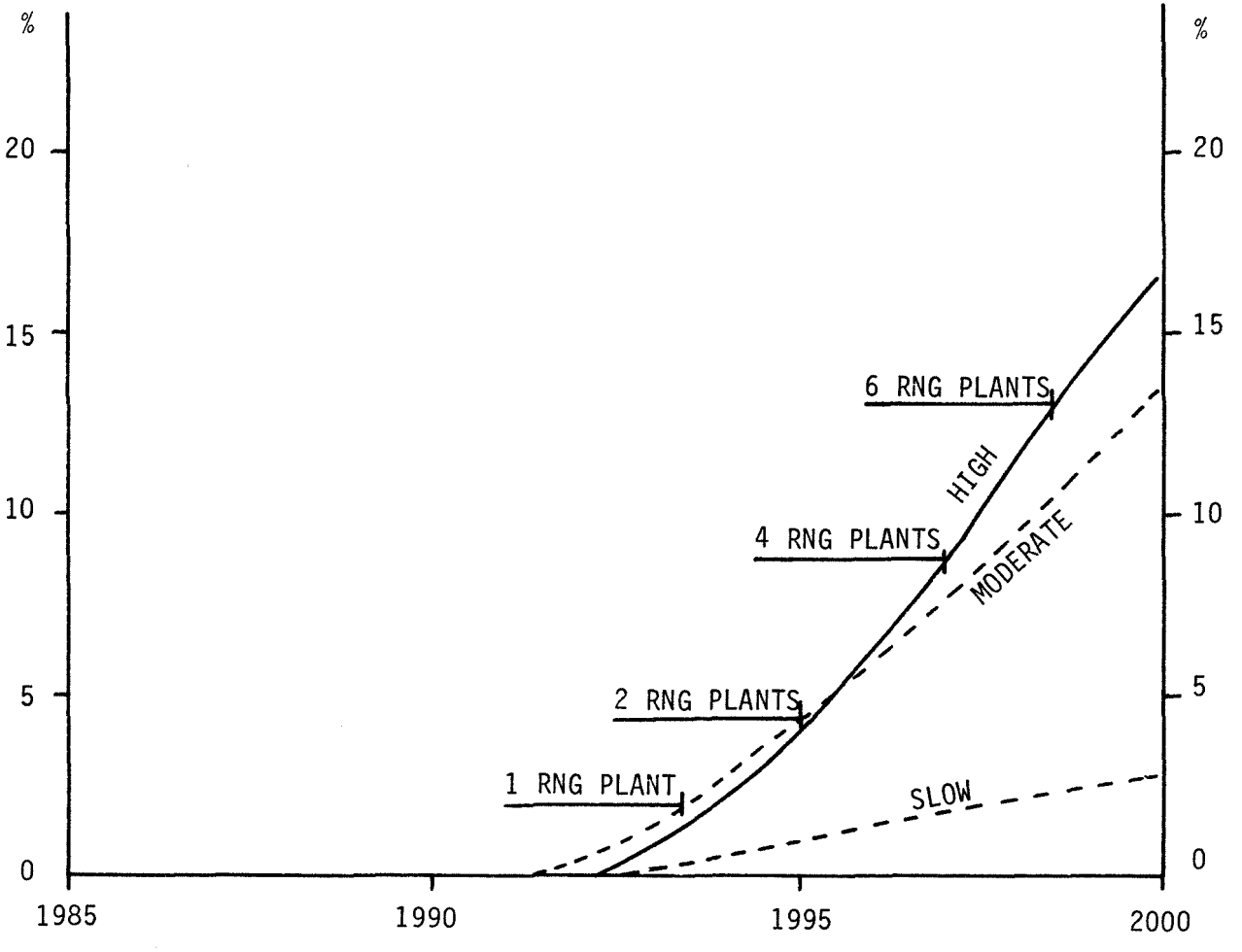


Figure 8-37. PERCENT REDUCTION IN GASOLINE DUE TO METHANOL CARS

more easily implemented with methanol than gasoline and, therefore, the proper comparison would be DISC methanol versus conventional gasoline technology.) Because dissociated methanol shows promise of significant efficiency improvement over more conventional technology, it will be discussed at greater length.

The PROCO, M.A.N. FM and TEXACO TCCS have been tested with neat methanol. A 5.0-liter PROCO was tested by Ford in 1979-80 (Ref. 26). The results showed that the engine performed at least as well as methanol as a gasoline. However, there was no significant difference in energy efficiency between gasoline and methanol operations. The M.A.N.-FM engine has been operated on methanol in a medium duty applications (Ref. 53) (see Section D of this chapter) and can be downsized to light-duty (Ref 30). The TCCS (Ref. 27,28, 30) has been operated on methanol (see Section D) and has been built to a military 1/4 ton vehicle size, hence, it may have light-duty methanol potential.

One possible means for using methanol in a spark-ignition engine with significant improvements in efficiency can be achieved by the decomposition of the methanol into hydrogen and carbon monoxide. The improvements in efficiency result from three factors:

(1) The engine exhaust heat can be utilized to facilitate the endothermic reaction which provides an approximate 20% (5% vaporization, 15% dissociation) increase in the heat content of the dissociated products compared to liquid methanol.

(2) Because the dissociated gases have anti-knock properties, the compression ratio of the engine can be significantly increased relative to gasoline.

(3) The dissociated gases have a lean limit misfire point significantly below that of gasoline, thereby permitting an equivalence ratio of 0.5 and below. Liquid methanol limit is about 0.7, gasoline limit is about 0.83 - 0.80.

A conceptual diagram of a dissociated methanol fuel system is shown in Figure 8-38. Methanol is heated with engine coolant in a heat exchanger to produce vaporized methanol. The methanol vapor is then passed through a catalyst bed heated by exhaust gas where it is endothermically dissociated to produce H_2 and CO. A forecooler (using engine coolant) is used to reduce the gas temperature, hence raising the density of the gas. It is then mixed with air via a gas (propane-type) carburetor. The engine is operated lean ($\phi < 0.5$) and at compression ratio of about 12:1 to 14:1. Power for wide open throttle operation is provided by liquid methanol via a methanol carburetor.

Houseman and Purohit (Ref. 32) have calculated thermal efficiency improvements expected from a decomposed methanol fueled engine. They found a maximum expected efficiency improvement of 38% and a practically realizable improvement over a driving cycle of 30%. It should be noted that this efficiency improvement was in reference to a 8.2 compression ratio normally aspirated stoichiometric gasoline engine. The decomposed methanol-fueled engine was assumed to have a 12.1 compression ratio and to be turbocharged at

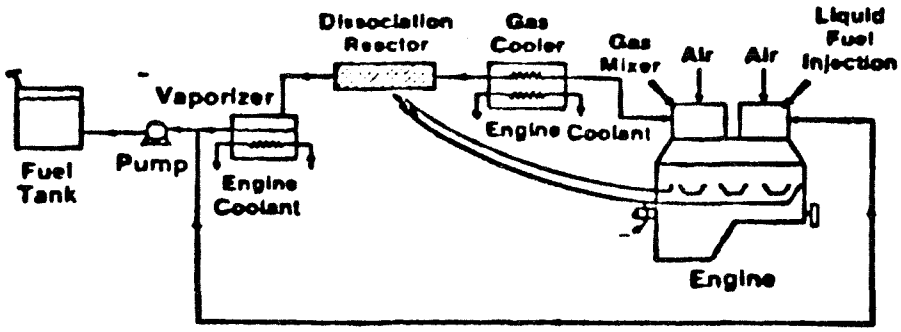


Figure 8-38. CONCEPTUAL FLOWSHEET (Ref. 31)

two atmospheres. Their calculations assumed a 12 percent increase in efficiency due to changing the compression ratio and further assumed that turbocharging and methanol decomposition were simultaneously possible.

Finegold, et al. (Ref. 31), at SERI, have tested a methanol decomposition system on an engine dynamometer. They found an approximate 40% - 50% increase in brake thermal efficiency. The efficiency improvement was relative to a General Motors 2.5 liter Citation engine. This engine operates near stoichiometric and has a compression ratio of 8.3 to 1. Significant modifications were made on this engine for the dissociation test. The pistons were changed and the compression ratio was raised to 14 to 1. The EGR and air injection systems were removed; the original carburetor was replaced by a gaseous propane carbureter and the ignition was modified with a closed-loop feedback, anti-knock system. For the test, throttle-setting and equivalence ratio were adjusted at each RPM/torque point to achieve maximum fuel efficiency.

Following the engine dynamometer test, vehicle chassis dynamometer tests were performed. The first series of these tests found a 37-42 percent efficiency improvement at constant speeds ranging between approximately 40 and 55 mph. A second series of tests found efficiency improvements between 34-26 percent, also at similar constant velocities. These results are tentative and at this time (July 82) a report has not been published. Results similar to the SERI findings have been reported by other researchers (Ref. 35, 36).

One analysis (Ref. 33) has been made of the implications of the current engine data on the dissociated methanol-fueled vehicles for city-cycle driving. Two dissociated methanol vehicle "paper designs" based upon the

previously described engines were compared to current gasoline engines. As an approximation to a full-driving cycle analysis, the panel on Hydrogen Automotive Engine Performance of the Fourth World Hydrogen Energy Conference utilized a weighted sum of three points on the brake-specific fuel consumption map to approximate city driving (Ref. 34). The results of this approximate calculation showed an efficiency improvement of between 21 and 43 percent for the dissociated methanol fuel vehicle. It should be noted that the higher efficiency improvement was for an engine that was significantly down sized and used liquid methanol to achieve higher power outputs when needed.

The research work to date implies an efficiency improvement of approximately 30-40 percent for the decomposed methanol engine over conventional current gasoline-fueled engines. However, future possible technical changes in the conventional gasoline engine including higher compression ratios and leaner operations could erode this apparent advantage. Of this 30 - 40% gain, about half could be realized without dissociation by using liquid methanol.

If dissociated methanol is compared to the gasoline base in the same manner as liquid methanol efficiency, improvements of 28 percent to 30 percent result, as shown in Table 8-25.

Over-the-road cost comparisons analogous to Figure 8-34 are shown in Table 8-26 and Figure 8-39. It should be noted that dissociated methanol technology is unlikely to achieve a commercial/producible level of maturity before the mid-nineties.

Table 8-25. DISSOCIATED METHANOL EFFICIENCY COMPARED TO GASOLINE BASELINE

YEAR	EFFICIENCY IMPROVEMENTS DUE TO				TOTAL IMPACT			
					EFFICIENCY FUEL FACTOR			
	EXHAUST HEAT RECOVERY INCLUDING VAPORIZATION	COMPRESSION RATIO	PUMPING LOSSES	LEANING	RANGE	BEST GUESS	RANGE	BEST GUESS
1987	20%	3-6%	1-2%	4-5%	28-33%	(30%)	1.59-1.53	(1.56)
1992	20%	3-4%	1-2%	3-4%	27-30%	(29%)	1.61-1.57	(1.59)
1997	20%	1-4%	1-2%	3-4%	25-30%	(28%)	1.63-1.57	(1.60)

Table 8-26. OVER-THE-ROAD FUEL COST GASOLINE VERSUS DISSOCIATED METHANOL (Cost in cents per Mile)

YEAR	GASOLINE	REMOTE NATURAL GAS METHANOL	5,000 T/D COAL METHANOL	10,000 T/D COAL METHANOL
1987	3.79	3.76	6.00	-
1992	4.46	3.63	5.86	5.32
1997	4.70	3.63	-	5.30

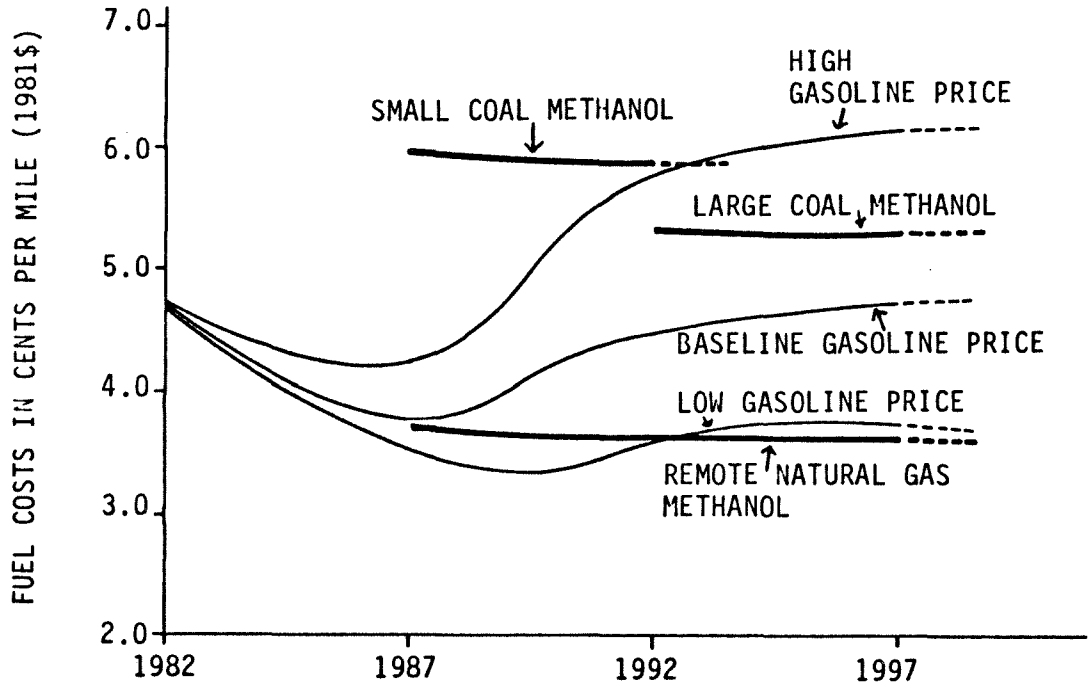


Figure 8-39. DISSOCIATED METHANOL VEHICLE VARIABLE FUEL COSTS

C. EMISSIONS FROM METHANOL-FUELED VEHICLES

1. Introduction

The key facts relating to emissions from automobiles in general will be briefly reviewed. The emission characteristics of methanol-fueled vehicles in particular will then be described.

Emissions from automobiles fall into the three categories: evaporative, crankcase, and exhaust. Crankcase emissions, which once accounted for about 25 percent of all hydrocarbon (HC) emissions, have now been virtually eliminated through improved engine design (Ref. 43). Evaporative emissions have also been significantly reduced in recent years. They account for 25 to 50 percent of all current vehicle HC emissions. Unregulated emissions include sulfates, particulates, and aldehydes. The latter will be especially significant with alcohol-fueled engines. Particulates are significant with diesel engines. Sulfates arise from the sulfur contained in gasoline and diesel fuel. The maximum allowed levels for the two fuels are 0.03 percent and 0.5 percent, respectively. (Note: a 0.05 percent sulfer limit for diesel has been proposed for the South Coast Air Basin.) Methanol contains no sulfur.

The photochemical smog typical of Los Angeles is the end result of the action of photochemical oxidants, notably the OH radical, on the hydrocarbons in the atmosphere. The OH radical is a major by-product of the reactions of NO, NO_2, and ozone, in the presence of water molecules and solar radiation. The various components of the hydrocarbon emissions differ in their tendency to form ozone. Methanol is among the least reactive while formaldehyde is moderatley reactive. The olefins and aromatics of gasoline are the most reactive.

The formation of exhaust-hydrocarbon emissions is most sensitive to the fuel-air ratio, fuel volatilization, and the design of the engine cylinders.

In spark-ignited engines, nitric oxide is formed at the end of the compression stroke and is "frozen" as the fuel-air mixture cools down at the start of the expansion stroke. The rate of formation of NO is proportional to the concentrations of nitrogen and oxygen and increases exponentially with temperature. Thus, for a fixed fuel-air ratio and spark timing, the amount of NO formed increases with compression ratio. Retarding the spark timing reduces NO formation. The formation of NO is most influenced by the fuel-air equivalence ratio (ϕ), as shown in Figure 8-40. ϕ is the volumetric fuel-air ratio at the given operating conditions divided by the stoichiometric volumetric fuel-air ratio. At low equivalence ratios (i.e., fuel-lean conditions) the combustion temperature is reduced, thus reducing NO formation. At fuel-rich conditions, NO formation is inhibited by the reduced availability of oxygen. Peak NO formation occurs at near-stoichiometric conditions for a ϕ value of 0.9. This generalizaton is true for all fuels. The use of exhaust-gas recirculation to reduce NO emissions depends on the lowering of combustion temperature and total oxygen concentration while maintaining the equivalence ratio. Carbon monoxide formation is generally favored by fuel-rich conditions.

The effect of equivalence ratio on the formation of NO, CO, and HC exhaust emissions underlies the importance of having equal distribution of

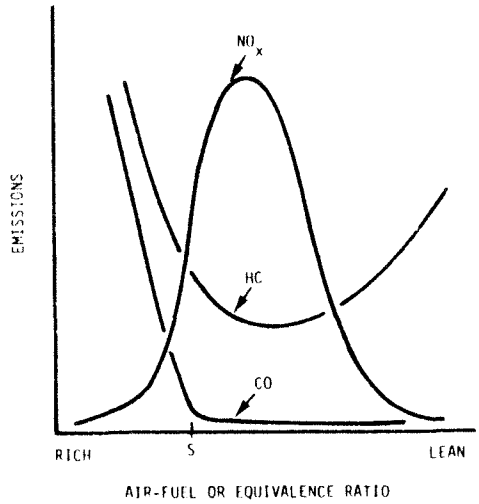


Figure 8-40. VARIATION OF HC, CO, AND NO CONCENTRATION IN THE EXHAUST OF A CONVENTIONAL SI ENGINE, WITH FUEL-AIR EQUIVALENCE RATIO

fuel among the engine cylinders and thus controlling the equivalence ratio at the desired level.

2. Exhaust Emissions from Neat-Methanol Engines

Much information is available on the emission characteristics of methanol-powered engines. A number of important results have been reported at international symposia on alcohol fuels (Refs. 45, 46). Fundamental studies on single-cylinder engines have been conducted by Brinkman and his associates at General Motors (Refs. 44, 49, 50). Computerized-modeling calculations and vehicle tests have been carried out by Pefley's group at the University of Santa Clara (Refs. 47, 48). Fuel tolerance tests using a range of methanol-gasoline blends have been performed by engineers at the Ford Motor Company (Ref. 51). Fleet tests have been made in the state of California.

The most important variables determining emissions from methanol-powered engines are fuel-air equivalence ratio, fuel preparation and delivery, spark timing, compression ratio, and combustion-chamber design.

a. Organic Emissions. Single-cylinder-engine investigations were made by Hilden and Parks (Ref. 44). A fuel-injected ASTM-CFR engine was operated at 1200 rpm and a compression ratio of 8 at MBT (minimum advance for best

torque) spark timing with clear Indolene (a standardized gasoline), methanol, and a mixture of 90 and 10 percent by volume of methanol and water. The fuel-air mixture was processed using two methods. In the standard method the incoming air was heated to 52°C and the fuel was at 30°C. In the improved method the heated air was mixed with nebulized fuel and then passed over a heat exchanger which raised the temperature to 60°C. The equivalence ratio was varied from stoichiometric to the lean limit which was 0.7 for Indolene and 0.62 for methanol. Unburned fuel (UBF) emissions were lowest at ϕ 0.9 for all the fuels. The ranges of UBF values for methanol were 4-5 micrograms per joule or 4-5 x 10^{-9} kilograms per joule (kg/J) with standard fuel preparation and 1-2 x 10^{-9} kg/J with improved fuel preparation. For gasoline they were 0.5-1-5 and 0.3-0.7 x 10^{-9} kg/J respectively. Aldehyde emissions for methanol fell from 0.9-1.5 to 0.075-0.3 x 10^{-9} kg/J as a result of improved fuel preparation. The aldehyde emissions from indolene were relatively insensitive to fuel preparation and were equal to about 5-10 percent of the methanol emissions. The methanol-water blend had about 20 percent higher UBF levels than methanol, but aldehyde emissions were about equal.

Engine speed may also be a factor in aldehyde emissions. Pischinger and Kramer (Ref. 45) reported that emissions at 4500 rpm were 54-76 percent lower than at 2500 rpm.

Kamaga, et al. (Ref. 46), showed that UBF emissions were reduced by 80 percent by heating the fuel-air mixture to 77°C. As the compression ratio (CR) was increased from 8 to 11 at stoichoimetric conditions, UBF rose by 20 percent. The addition of 1 percent aniline to the methanol fuel caused a 54 percent reduction in exhaust aldehydes at CR = 11. It is probable that the aniline reacted with formaldehyde to form the corresponding imine. The presence of aniline reportedly did not affect NO_x emissions levels.

Brinkman (Ref. 49) found that UBF emissions increased with compression ratio but were little affected by retarding the spark timing. Values are given in Table 8-27.

b. Oxides of Nitrogen. The lowering of NO_x emissions for methanol-fueled engines relative to gasoline-fueled engines is primarily due to the reduction in combustion temperature. In the work of Hilden and Parks (Ref. 44), using a standard ASTM-CFR, single-cylinder engine, it was shown that NO_x emissions for methanol were about 50-60 percent of those for gasoline.

NO_x emissions for methanol increase with engine compression ratio. This fact represents a constraint upon the potential gains in efficiency achievable by operating a methanol-powered engine at high compression ratios. Brinkman (Ref. 49) carried out a systematic investigation at 1200 rpm with a single-cylinder Removable Dome Head (RDH) engine whose fuel-air mixture was heated using a heat exchanger in the feed line. The compression ratio was varied from 8 to 18 and the equivalence ratio from 0.7 to 1.1. The spark timing was first set at MBT and then retarded by 2, 5 and 10 degrees. For each set of conditions the indicated power and efficiency were measured along with emissions. Table 8-27 is a selection of the results.

Table 8-27. EXHAUST EMISSIONS AS A FUNCTION OF OPERATING VARIABLE FOR METHANOL ENGINE

NITROGEN OXIDES

	NITROGEN OXIDES $\frac{kg}{J} \times 10^9$					
COMPRESSION RATIO / Spark Timing	8:1		12:1		18:1	
	MBT	-5°	MBT	-5°	MBT	-5°
ϕ = 0.7	0.5	0.3	0.9	0.5	1.6	0.9
ϕ = 0.9	3.0	2.3	4.2	2.5	4.7	3.0
ϕ = 1.1	1.2	1.0	1.35	1.2	1.45	1.3

UNBURNED FUEL

	UNBURNED FUEL $\frac{kg}{J} \times 10^9$					
COMPRESSION RATIO / Spark Timing	8:1		12:1		18:1	
	MBT	-5°	MBT	-5°	MBT	-5°
ϕ = 0.7	1.1	1.1	1.5	1.5	1.9	1.8
ϕ = 0.9	0.5	0.3	0.9	0.7	1.3	1.1
ϕ = 1.1	1.6	1.2	1.9	1.5	2.4	2.1

The above data were selected from Brinkman (Ref. 49).

The results from single-cylinder engines are entirely consistent with the predictions from thermokinetic combustion models such as those developed by Pefley and his co-workers (Ref. 47).

c. Carbon Monoxide Emissions. The results of single-engine studies and fleet tests have consistently shown that CO emissions for neat methanol and gasoline are comparable. In tests using a single-cylinder engine, Hilden and Parks (Ref. 44) noted that CO emissions were minimum at an equivalence ratio of 0.85 and were further reduced by 70 percent when the incoming fuel-air mixture was heated to 60°C.

Kamaga, et al. (Ref. 46), observed very little change in CO emissions when the compression ratio was varied from 7 to 11. They did note that the general relationship between equivalence ratio and CO emissions was the same for methanol as for gasoline (see Figure 8-40).

3. Exhaust Emissions for Vehicles Fueled with Gasoline-Methanol Blends

Nearly all the data available was obtained with actual vehicles. In most of the early work methanol was simply added to gasoline in the amount of 5-25 percent without supplementary higher alcohols to promote miscibility. The stoichiometric air-fuel ratio of methanol is 6.45 while that of gasoline is 14.6. Hence if the vehicle is operated at its normal gasoline setting the mixture will be relatively fuel-lean. This phenomenon is sometimes called the "leaning effect" of the methanol on the gasoline. In terms of the relationships between emissions and equivalence ratio shown in Figure 8-40, there would be changes depending on the initial air-fuel ratio. Furthermore, in the absence of heat exchange between the fuel intake and exhaust, fuel maldistribution would be a potentially more serious problem for carbureted vehicles because of the increased flow rate of fuel.

Fleet tests were carried out by researchers at the University of Santa Clara (Ref. 48) on automobiles with an electronic fuel-injection system with closed-loop feedback control, which is standard equipment for the Toyota Supra and Cressida. The oxygen sensor and control system automatically compensated for fuel-leaning effects over a range of methanol percentages. The vehicles were equipped with the three-way catalyst system, whose operation was very sensitive to the air-fuel ratio. All the emissions met California standards. NO_x and UBF emissions increased with an increase in the percentage of methanol while CO decreased. As expected, aldehyde emissions increased with methanol content.

Brinkman and Gallapoulos (Ref. 50) used 1973 model vehicles with carbureted V-8 engines and found reductions of about 40 percent in CO and 10 percent in NO_x with a 10/90 methanol-gasoline blend as compared with gasoline. When the carburetor was reset to operate at 6 percent rich, the reductions were 10 percent for UBF, 20 percent for CO, and 10 percent for NO_x. All the reductions were attributable in part to the leaning effect.

More recently (Ref. 52) the Atlantic Richfield Company (ARCO) presented emissions data in connection with a waiver application for a fuel typically

containing 4.5 percent methanol and 4.5 percent fuel-grade tertiary-butyl alcohol and 91 percent unleaded gasoline. The ARCO data indicated that, for vehicles equipped with standard emission-control devices, there was no significant difference in exhaust emissions between the alcohol blend and pure gasoline. When the vehicles were operated continuously for 50,000 miles no significant differences in emissions were observed. Three automobile manufacturers did express reservations about the longer-term impact of the blend on evaporative emissions and exhaust catalyst durability. The important observation from all the available evidence is that exhaust emissions for methanol-gasoline blends vary according to the air-fuel-ratio setting for the vehicle.

D. METHANOL FUEL POTENTIAL IN MEDIUM- TO HEAVY-DUTY ENGINES

1. Background

Heavy and medium trucks and transit buses use approximately 0.30 quads of energy per year in the State of California (approximately 2.3×10^9 gallons of diesel fuel). This consumption is expected to approximately double by the year 2000. If this energy use was methanol, it would imply roughly 40-50 thousand tons of methanol per day in 1980, and roughly 80-100 thousand tons of methanol per day by the year 2000.

For analysis of possible transitions to methanol, this submarket is important not only because of its potential size. The logistics of the fuel supply is simpler than that for private automobiles. On-site central refueling, combined with major interstate truck stops, can provide an adequate supply infrastructure as it does with diesel today. Methanol engines could penetrate this market more rapidly than that of private passenger cars. With the possible exception of transit vehicles, heavy-duty vehicle purchasers have a greater ability to specify the engine transmission system when purchasing new vehicles than buyers of private passenger cars. While most transit vehicles and medium- and heavy-duty trucks are longer lived than private cars, the engines are subject to replacement or major overhaul more frequently. For example, transit buses are subject to major powerpack (engine and transmission) overhaul or replacement every 150 to 200 thousand miles. In normal operations, this would occur every two to four years (Ref. 53). Some heavy-duty truck applications are subject to more frequent overhaul than this. In principle, conversion to a methanol engine could take place at any major overhaul or engine replacement.

However, for this potential to be realized, at least three requirements must be met.

(1) Methanol engines appropriate for medium- and heavy-duty truck and transit applications must exist in the domestic marketplace.

(2) A limited fuel-methanol supply infrastructure must be in place.

(3) Total costs for the methanol engine operation must be equivalent, or less, than those for the diesel engine.

A potential buyer of a methanol engine, either for specification in a new vehicle purchase or as a replacement for an existing engine, requires sufficient "in-use" information on the methanol to be confident in the economy and reliability. Without such information, a potential buyer cannot assess whether the methanol engines will, in fact, meet their specific needs, or will produce bottomline costs lower than diesel.

2. Candidate Methanol Engine Technologies for Medium- and Heavy-Duty Applications

Most of the emerging technologies appropriate for medium- and heavy-duty applications combine direct injection into the combustion chamber

with a stratification of the charge. The current exceptions to this is the design by Daimler Benz which utilizes fully vaporized methanol in a uniform charge Otto-cycle operation and the dual fuel design by Volvo. The various technologies are summarized in Table 8-28.

As representative of the approaches to methanol engines, the M.A.N. FM, the Daimler Benz, and the Texaco TCSS 292 will be described in more detail.

3. M.A.N. FM Engine*

Table 8-28. ENGINE TECHNOLOGIES APPROPRIATE FOR MEDIUM- TO HEAVY-DUTY METHANOL APPLICATIONS

ENGINE	FEATURES	COMPATIBLE FUELS		
		Good Octane	Good Cetane	Multi-Fuel
TEXACO TCSS 292	Redesign of TCSS for UPS delivery trucks.	Yes	Yes	Yes
MAN FM	Retrofitted diesel; spark plug piston reshaped; hot wall combustion chamber; CR=16-18, exhaust catalyst.	Yes	Yes	Should
FORD PROCO	Aiming at ultra-lean combustion and minimizing octane requirement with high compression ratios.	Yes	No	No
VOLVO	Two injection systems; MeOH & diesel; diesel pilot charge; ignition source (spark plug).	Yes in conj. w/diesel	Yes	L'td.
DEUTZ	Ignition source (spark plug).	Yes in conj. w/diesel	Yes	L'td.
DAIMLER BENZ	Vaporized MeHO in converted diesel (open chamber); no exhaust catalyst CR=10.5	Yes	No	No

* The Acurex Corporation has recently completed an evaluation of methanol-fueled, heavy-duty engines for the California Energy Commission. The following sections on the M.A.N. and Daimler Benz engines are excerpted from Section 4 of that report with some additions as noted (Refs. 53 to 60).

The M.A.N. FM multifuel combustion system is based on direct fuel injection and spark assist. Figure 8-41 shows the combustion chamber design of the D 2566 FMUH engine with spark plug, injector, and cupped piston. The primary characteristics of the FM design are:

(1) Diesel-type compression ratio.

(2) Direct injection.

(3) Wall deposition, diffusion flame combustion.

(4) Conventional spark ignition system.

The "FM" combustion process is governed by fuel stratification and mixture formation. Fuel, injected directly on cupped piston walls, evaporates and burns as a diffusion flame. Fuel is successively fed into the flames by the air rotating in the combustion chamber. The greater part of the heat necessary for fuel vaporization is supplied by flame radiation. The rate of mixture formation and wall deposition controls the following combustion characteristics:

(1) Ignition rate.

(2) Rate of pressure rise.

(3) Engine noise.

Fuels tested by M.A.N. include diesel, gasoline, methanol, and ethanol. Performance data for three methanol engines (L 9204 FM, D 0836 FM, D 2566 FM) are available from bench and bus demonstration programs. Due to Germany's high dependence on imported petroleum, the German Federal Government funded M.A.N. to operate small methanol-powered buses in Berlin.

The Auckland Regional Authority (ARA), New Zealand, is conducting a methanol bus competition between M.A.N. and Mercedes-Benz. Program objectives emphasize economics rather than emissions. Maintenance and operating costs highlight the comparison. Even so, there is strong competition, since ARA guarantees the sale of 400 buses to the victor. The program started July 29, 1981, and only preliminary information is available. In this program, the M.A.N. engine is partly throttled for better idle performance -- to what extent was not disclosed.

The performance and fuel consumption of the D 2566 FMUH engine on methanol and diesel, as reported by M.A.N., is seen in Figure 8-42. Torque was higher with methanol than diesel for all speeds with the maximum at 1000 rpm. Brake Specific Fuel Consumption (BSFC) is also higher for methanol but is consistent with the differences in energy densities. Figures 8-43, 8-44, and 8-45 shows the BSFC maps for both diesel and methanol. Figure 8-46 shows the results of the Berlin city bus demonstration. Methanol consumption is higher than diesel, but, when adjusted for energy content, methanol fuel consumption is lower than diesel by 5.25 percent.

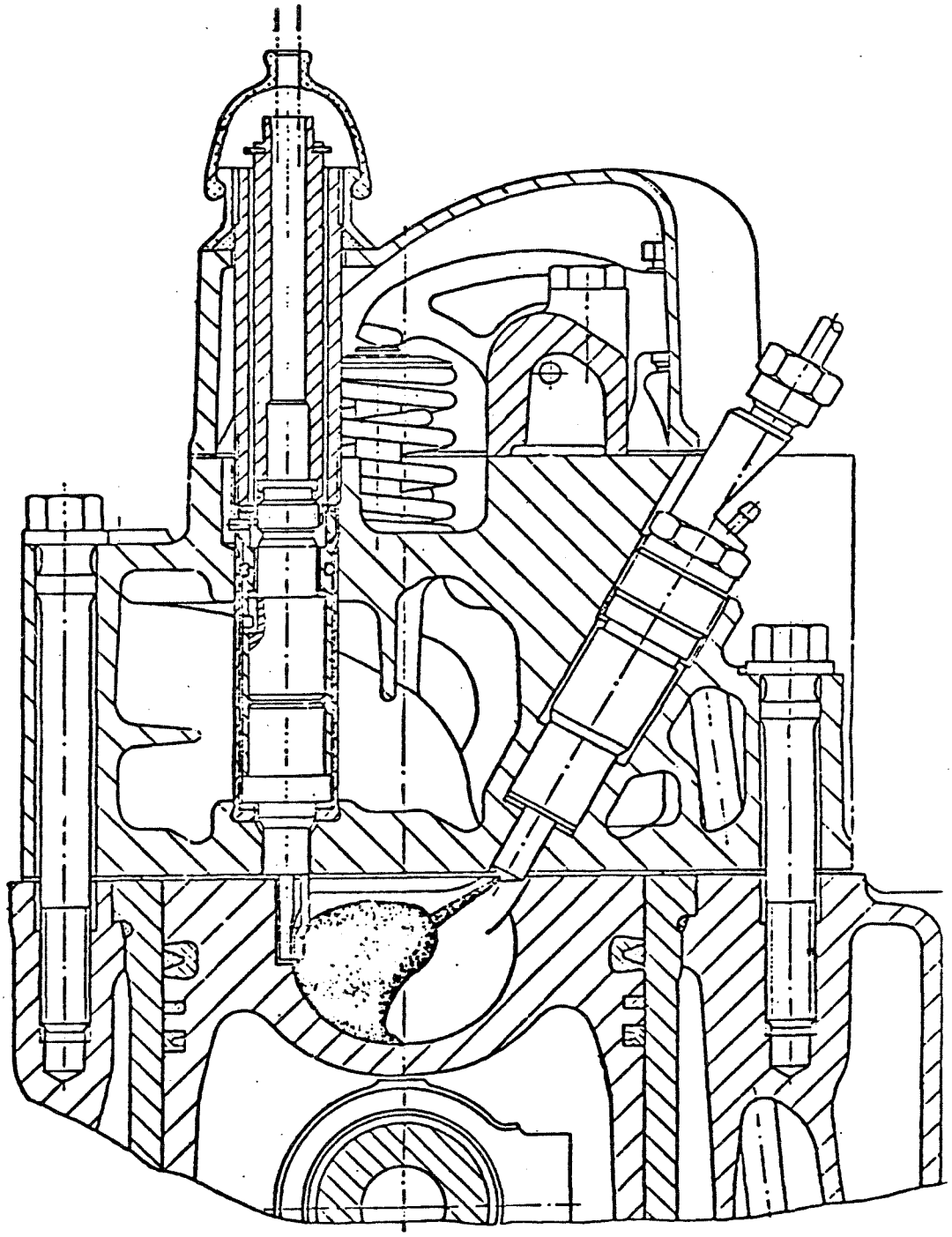


Figure 8-41. CROSS SECTION M.A.N. D2566 FMU METHANOL ENGINE (Ref. 53)

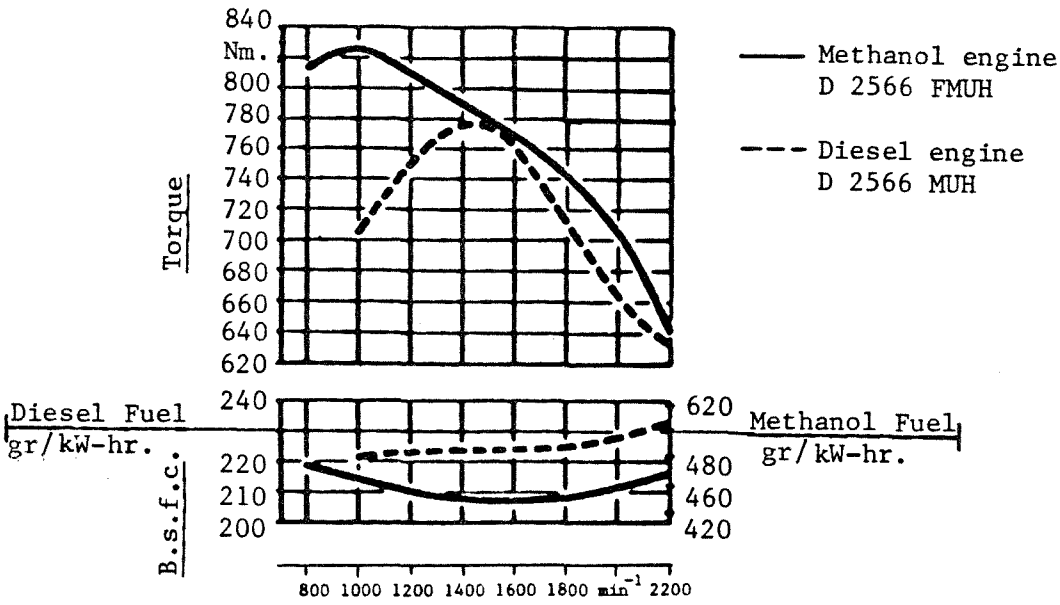


Figure 8-42. FULL-LOAD CHARACTERISTICS OF THE M.A.N. D 2566 FMUH METHANOL ENGINE COMPARED WITH DIESEL ENGINE D 2566 MUH (Ref. 53)

The cupped piston design and high-compression ratio (CR=16:1) are claimed to eliminate engine wear and cold-start problems. Since injection is made directly into the piston cup, fuel contacting the cylinder walls is reduced. M.A.N. claims successful cold starts to -20°C as a result of high compression ratios and corresponding high in-cylinder gas temperatures (500° to 600°C) and spark-assist.

The M.A.N. FM system capitalizes on high heat of methanol vaporization to increase engine efficiency. Methanol vaporization, the result of fuel sprayed on the hot piston surface, recovers part of the energy otherwise lost to the environment. Engine efficiency greater than 40 percent is claimed throughout much of the speed range with performance peaking at 41 percent (1,000 rpm, 6.25 bar mean effective pressure).

All emission species are equal to or below 1982 California standards for the 13-mode federal driving cycle (Figure 8-37), with significant reductions noted for CO and NO_x. Emissions are reported with the use of an exhaust catalyst which does not permit clear evaluation of baseline engine conditions. As expected, no exhaust discoloration is seen with neat methanol (Figure 8-38), while comparable diesel fuel experiments show exhaust discoloration between 1 and 3 Bosch Smoke units.

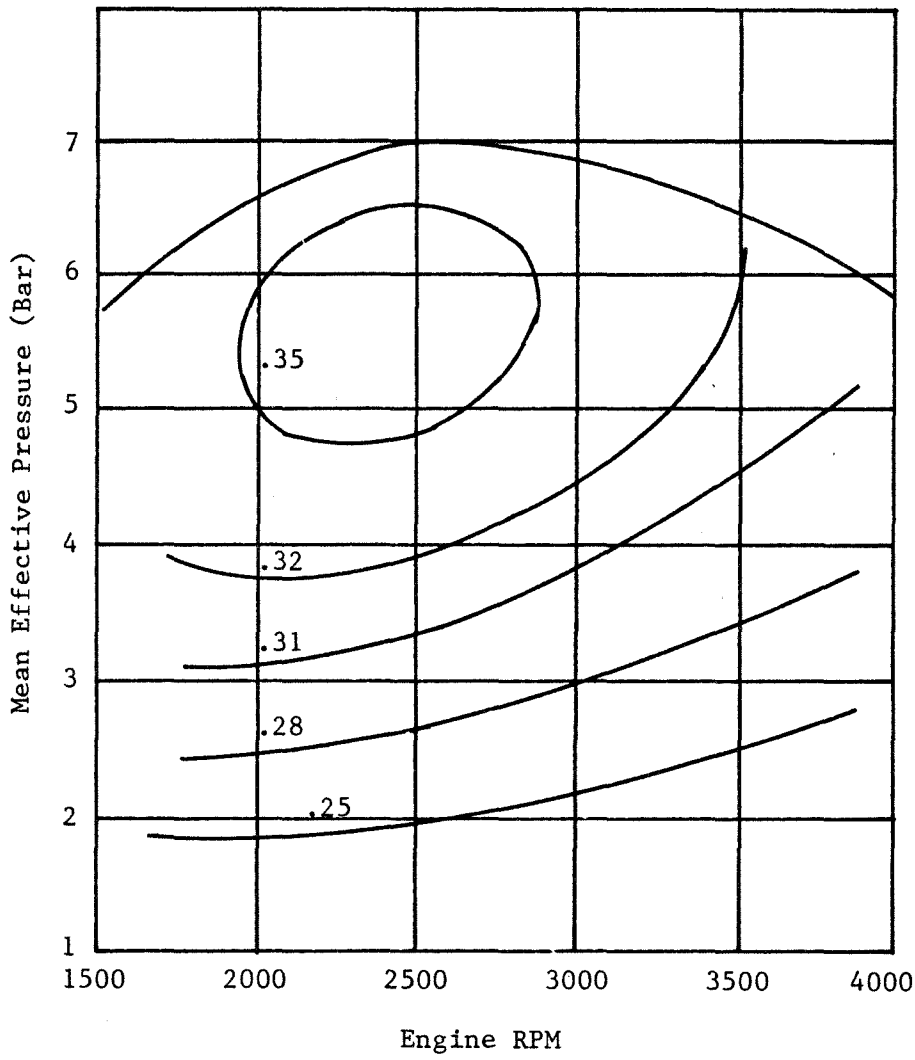


Figure 8-43. BRAKE THERMAL EFFICIENCY OF THE M.A.N. L9204 FM DIESEL ENGINE (Ref. 53)

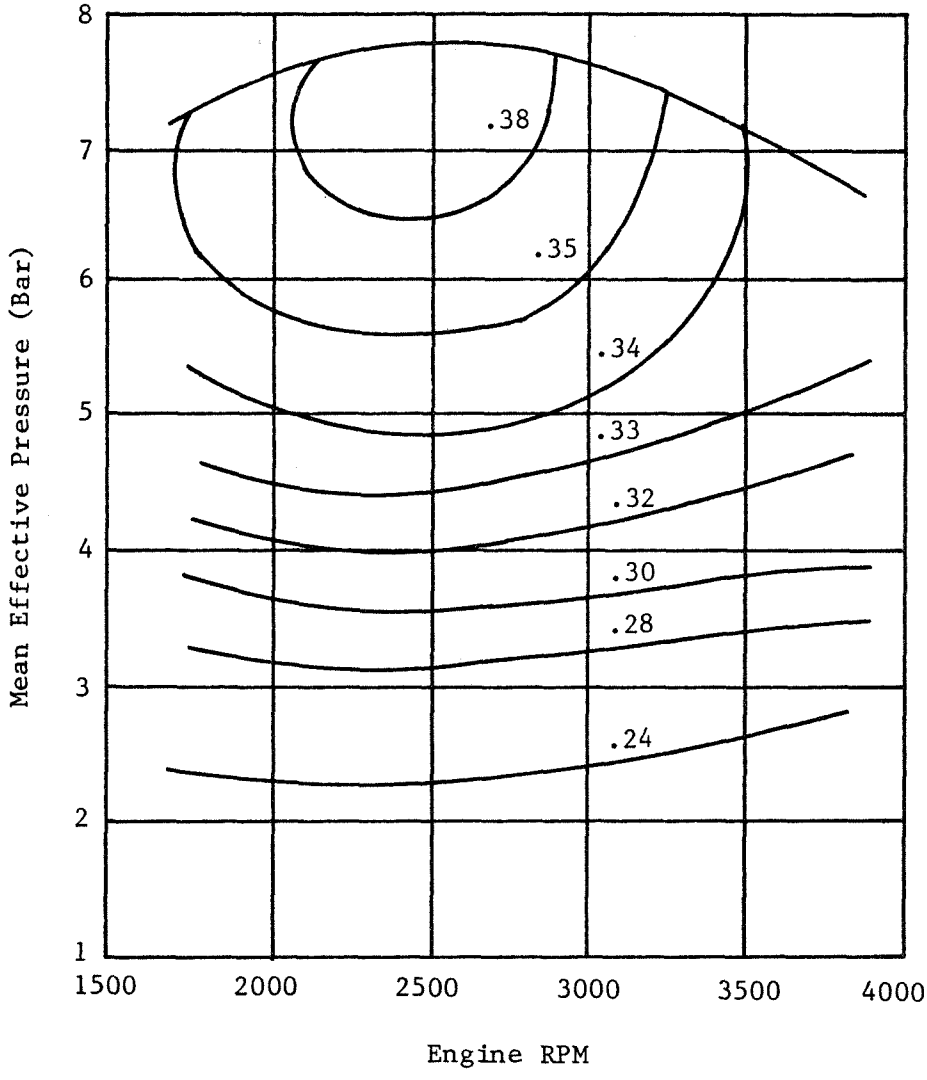


Figure 8-44. BRAKE THERMAL EFFICIENCY OF THE M.A.N. L9204 FM METHANOL ENGINE (Ref. 53)

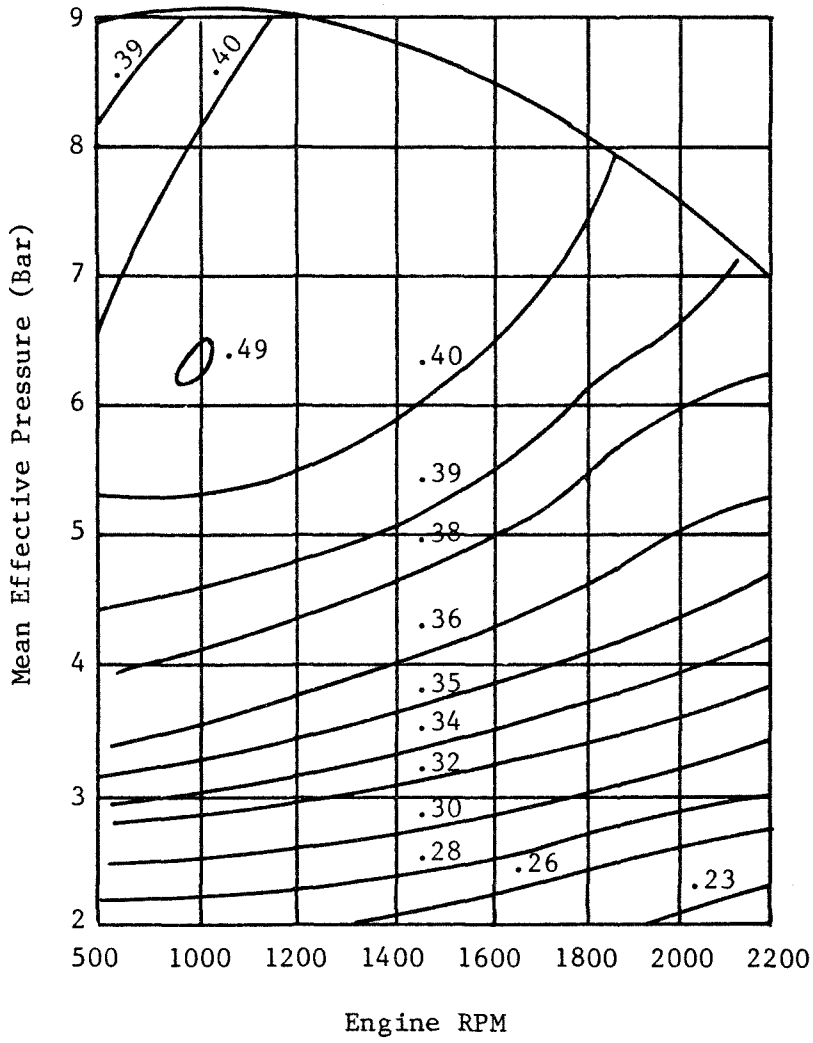


Figure 8-45. BRAKE THERMAL EFFICIENCY OF THE M.A.N. 2566 FMUH METHANOL ENGINE (Ref. 53)

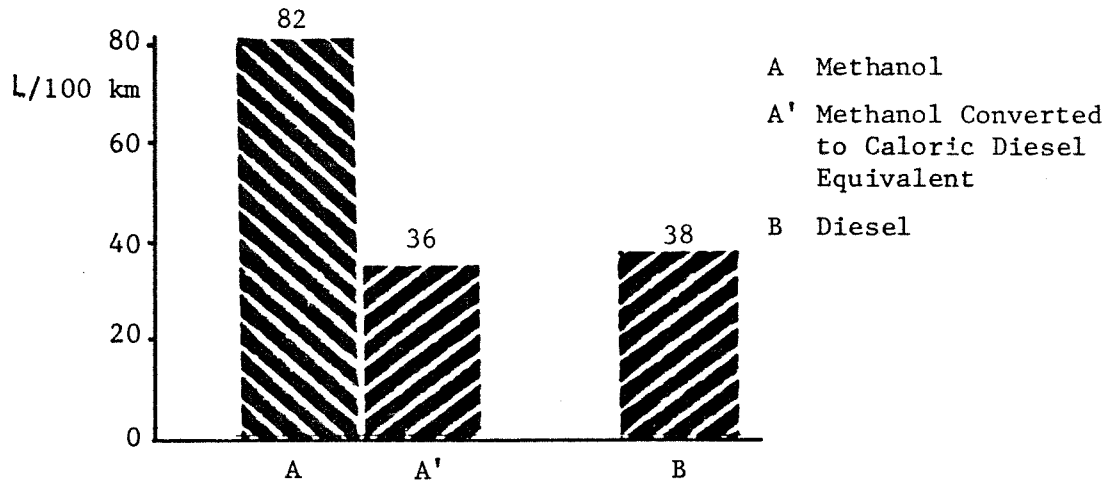


Figure 8-46. FUEL CONSUMPTION OF M.A.N. CITY WITH BUS D 2566 FMUH METHANOL ENGINE (Ref. 53)

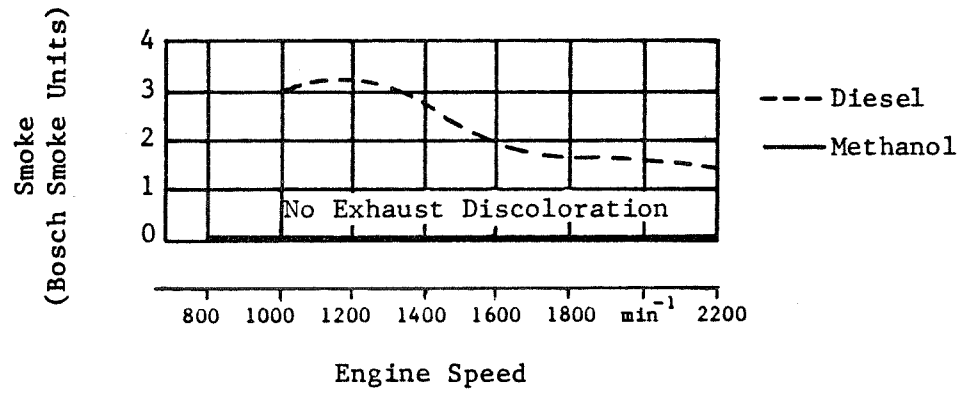


Figure 8-47. THIRTEEN-MODE CYCLE RESULTS OF THE M.A.N. D 2566 FMUH METHANOL ENGINE (Ref. 53)

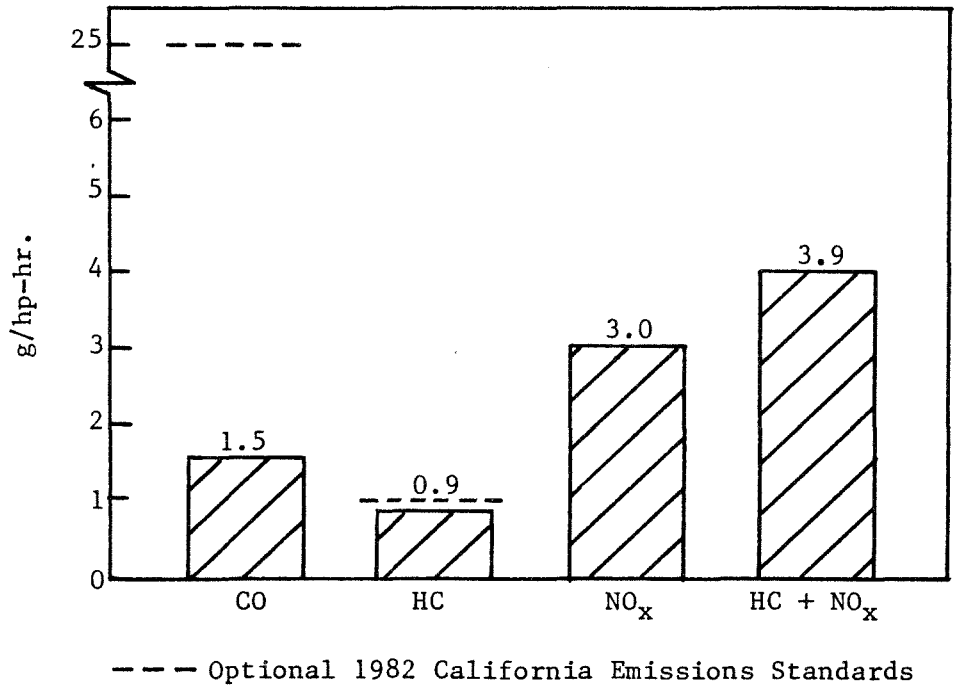


Figure 8-48. FULL-LOAD CHARACTERISTICS OF THE M.A.N. D 2566 FMUH COMPARED WITH DIESEL ENGINE D 2566 MUH (Ref. 53)

Since M.A.N. does not yet commercially produce methanol engines, no hardware cost information is available. From a technical observation, the following components will add to the cost of the base-diesel engine:

(1) Addition of spark plugs in the cylinder heads.

(2) Addition of ignition source.

(3) Redesign of the fuel injection pump and injectors to avoid wear and double output capacity.

The M.A.N. process probably requires the minimal amount of component redesign and hardware cost due to its similarity to conventional diesel operation.

The advantages of the M.A.N. combustion system, as reported by M.A.N., are:

(1) High torque, efficiency, and performance.

(2) Multifuel capability if required.

(3) Good cold-start characteristics.

4. Daimler Benz M 407 hGO Engine

Mercedes-Benz has developed a vaporized, spark-assisted methanol engine similar in design to their LPG versions. Methanol, vaporized in a heat exchanger fed by the engine coolant, is supplied to the engine through a standard gas carburetor. In this way, waste heat, up to 5.3 percent, is recovered in the form of usable energy. The flow diagram of Figure 8-49 shows points of energy recovery and primary component parts. Figure 8-50 shows the control system for the engine.

An auxiliary methanol-fired heater is used to preheat engine coolant for cold start purposes. The engine coolant is temporarily constrained between vaporizer and heater until sufficient thermal energy is available to initiate fuel vaporization and maintain cold engine operation. Once the engine is warm, the heater is turned off unless needed to heat the vehicle interior. Figure 8-51 shows the drive system with energy recovery and heater unit.

Figure 8-52 shows the Mercedes Benz M 407 hGO engine combustion chamber configuration with dished piston, spark plug, and swirl free inlet ports. The basic combustion principle is similar to the Otto cycle with two differences noted. First, lean combustion as part load is possible because fuel is introduced as a gas. The excess air ratio is typically 15 percent. Similar to "lean" heterogeneous diesel combustion, lean combustion of homogeneous mixtures produce high-engine efficiency. Second, unlike the standard Otto engine, air throttling is only required at very low speed to overcome rough running. These differences are shown in Figure 8-53. Therefore, cycle performance lies somewhere between the diesel and Otto engines.

Germany, New Zealand, and Brazil are demonstrating Mercedes-Benz buses fueled with methanol. New Zealand reports poor fuel consumption, 111.3 liters/100 km (44.5 liters/100 km diesel equivalent), during the first 5000 km of service. By comparison, the standard Mercedes-Benz diesel fitted in an identical vehicle achieves 38 to 42 liters/100 km. Corrections made to the methanol control system are anticipated to improve performance. These results are displayed in Figure 8-54. This shows the 11 percent decrease for fuel efficiency for the methanol engine.

Figure 8-55 shows the performance of the M 407 hGO engine at full power for all speeds. Comparative baseline diesel or LPG data are not published. Maximum power and torque are similar to M.A.N. for methanol. Peak engine efficiency for the "alcohol gas engine," as it is called, is claimed to be 41 percent. The gain in thermal efficiency, compared to the Otto engine (about 30 percent), is attributed to the fuel vaporization energy recovery scheme. Resolution to the discrepancy between New Zealand's poor fuel consumption and Mercedes-Benz's reported 41 percent thermal efficiency is not clear. As mentioned, modification to the fuel control system may clarify the issue.

No particulates, lead, or sulfates are measured from the combustion of methanol. Diesel particulate data are not available, since this engine is a derivative of their LPG versions. At 15 percent excess air, gaseous emissions are very low without the use of an exhaust catalyst. Results of the 13-mode Federal Test Procedure are plotted in Figure 8-56.

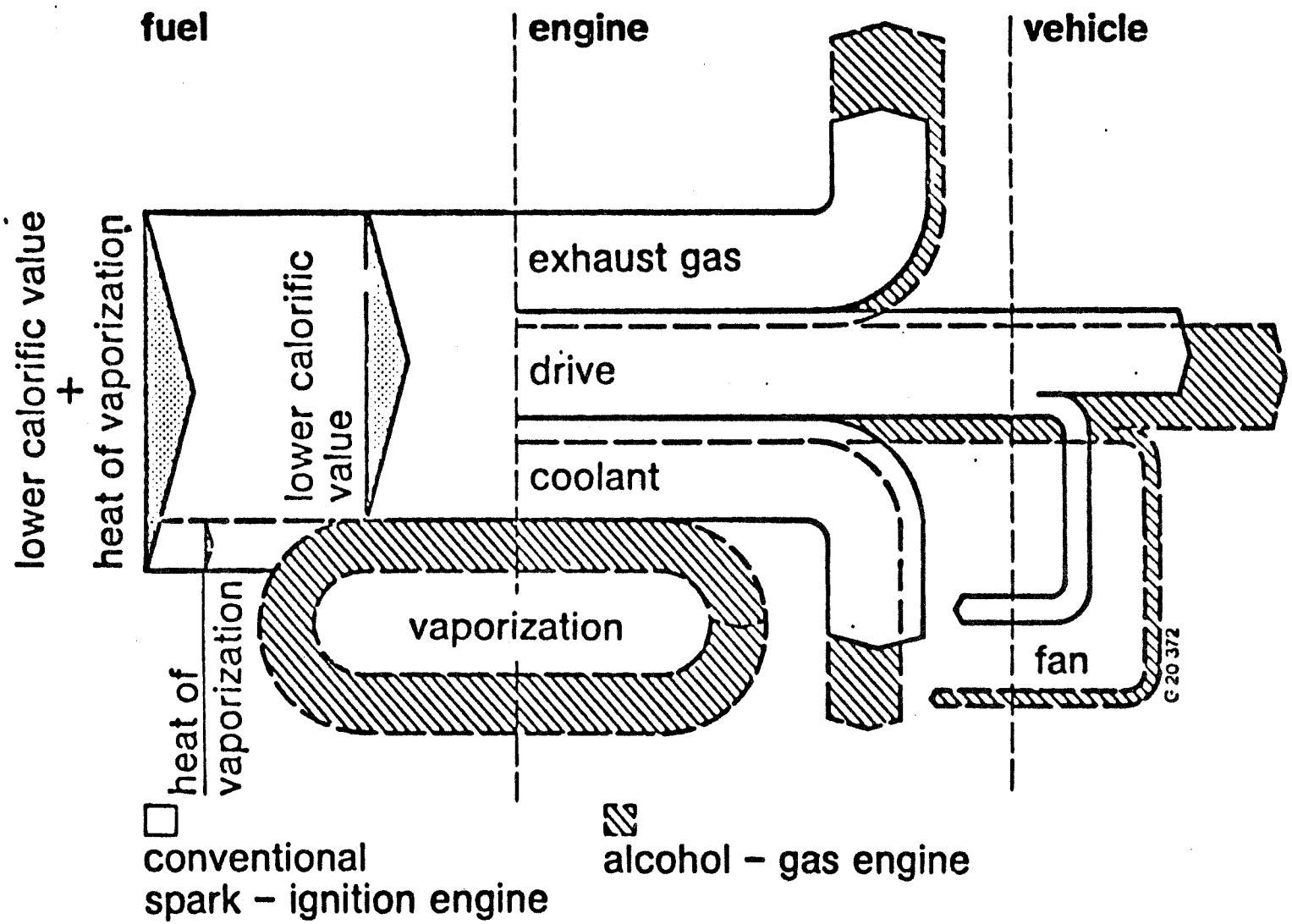
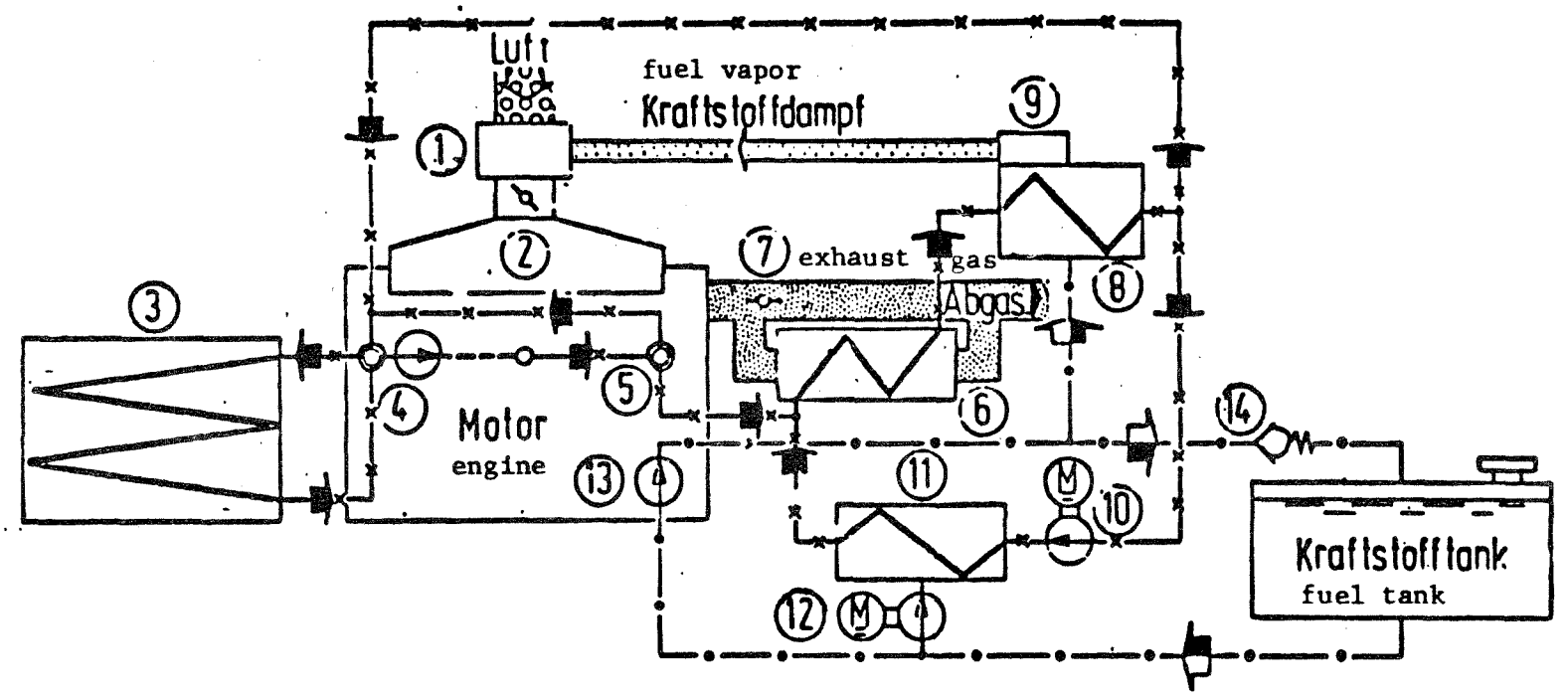
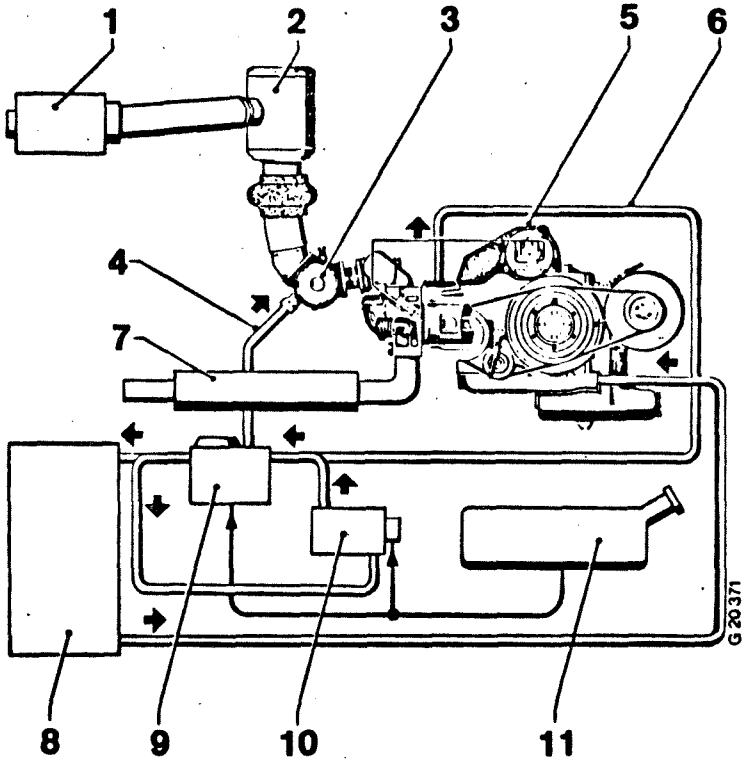


Figure 8-49. ENERGY FLOW DIAGRAM OF MERCEDES-BENZ M-407 hGO (Ref. 53)



1. gas mixer
2. intake pipe/throttle flap
3. vehicle radiator
4. water pump/thermostat
5. 3/2-thermostat valve
6. exhaust gas heat exchanger
7. exhaust gas control flap
8. fuel evaporator
9. pressure regulating valve
10. electric water pump
11. auxiliary heater
12. electric fuel pump
13. operating fuel pump
14. overflow valve

Figure 8-50. CIRCUIT DIAGRAM MERCEDES-BENZ ALCOHOL GAS ENGINE (Ref. 53)



① cyclone-type preliminary filter
② air filter
③ gas mixer
④ methanol vapor
⑤ methanol-gas engine
⑥ engine coolant
⑦ silencer
⑧ radiator
⑨ methanol vaporizer
⑩ cold start heater
⑪ methanol tank

Figure 8-51. FUNCTIONAL DIABRAM OF MERCEDES-BENZ METHANOL DRIVE SYSTEM (Ref. 53)

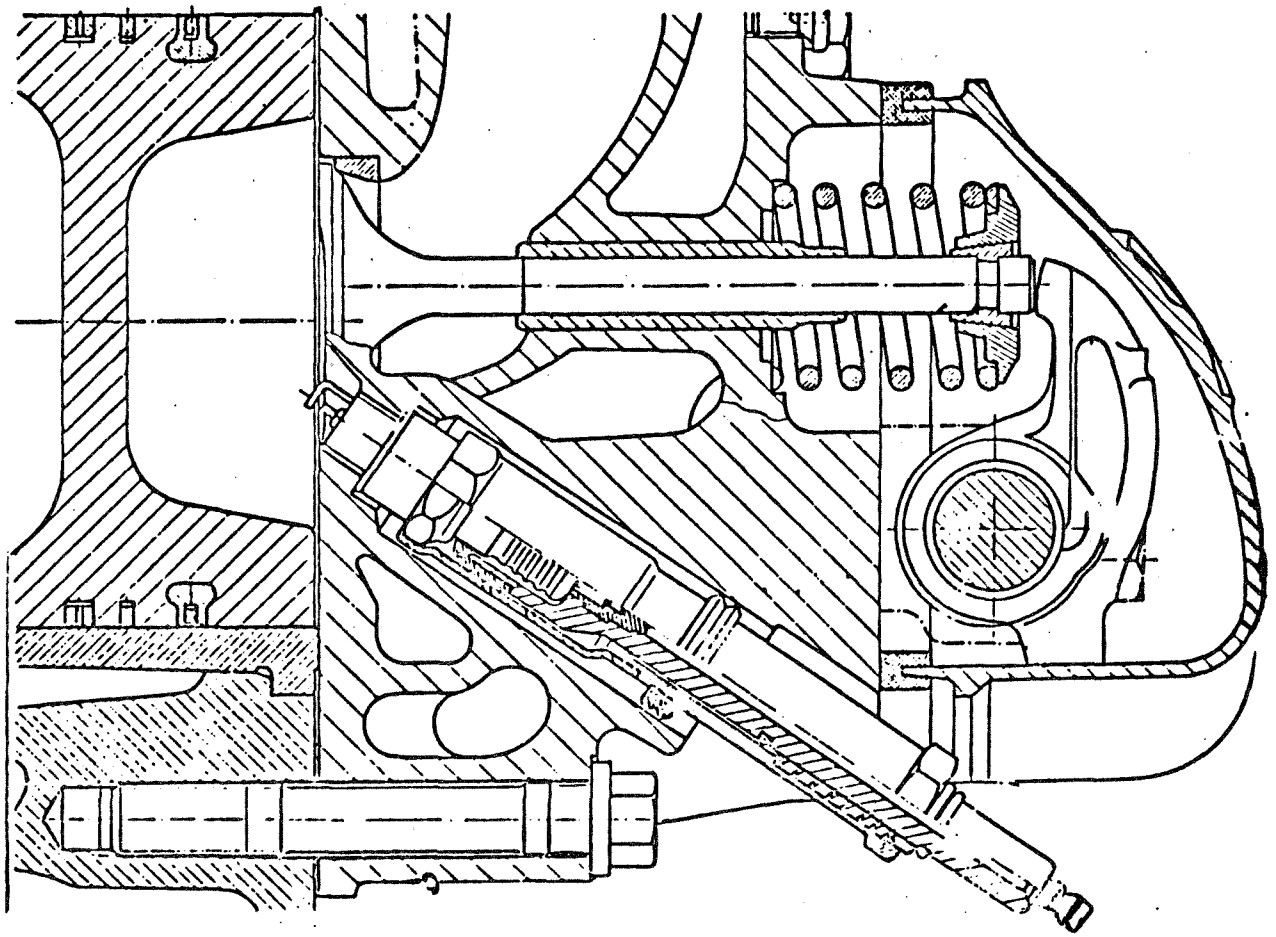


Figure 8-52. COMBUSTION CHAMBER CONFIGURATION OF THE MERCEDES-BENZ M-407 hGO ENGINE (Ref. 53)

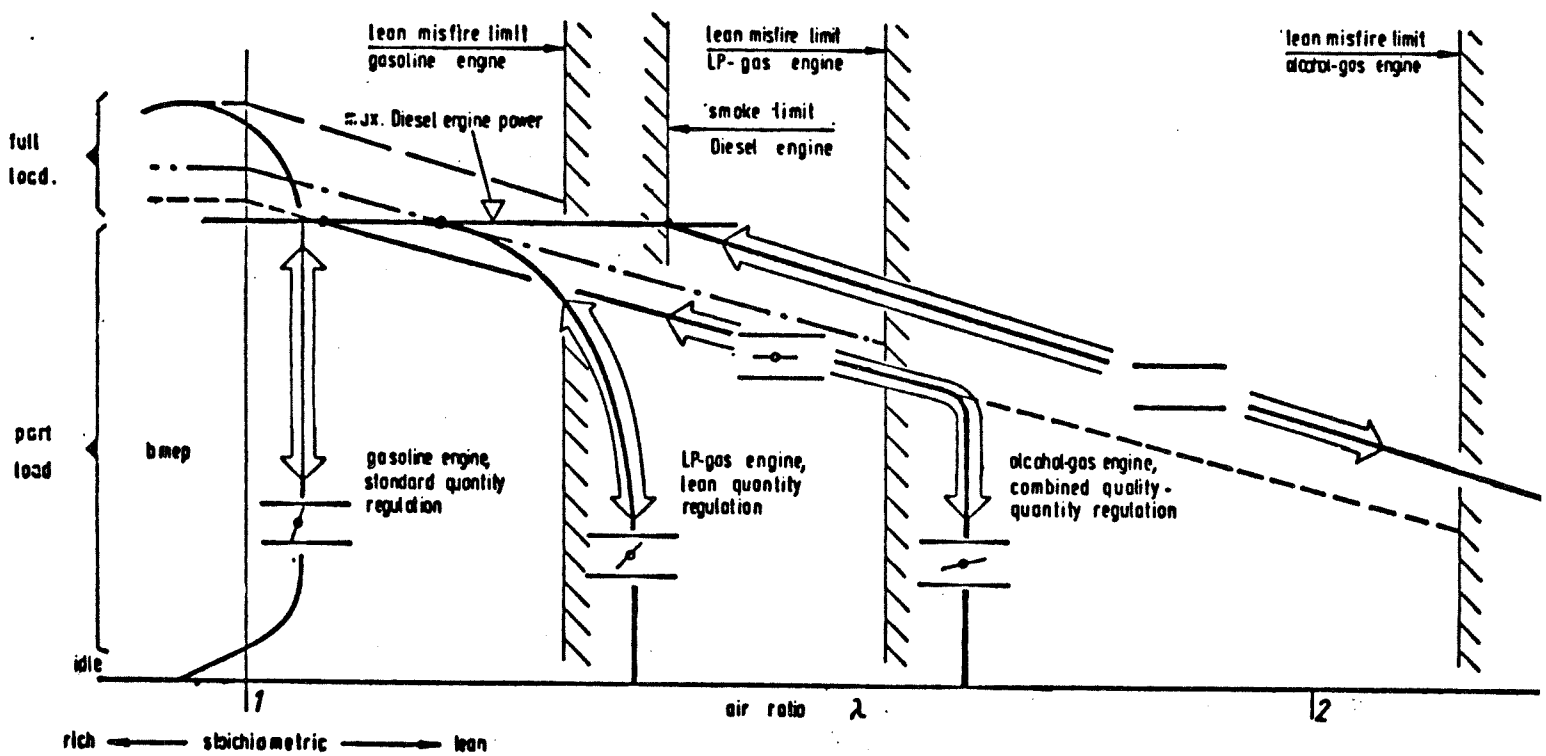


Figure 8-53. COMPARISON OF OPERATING RANGES, MAXIMUM OUTPUTS AND AIR RATIOS OF GASOLINE, LP-GAS, ALCOHOL-GAS AND DIESEL ENGINES (Ref. 53)

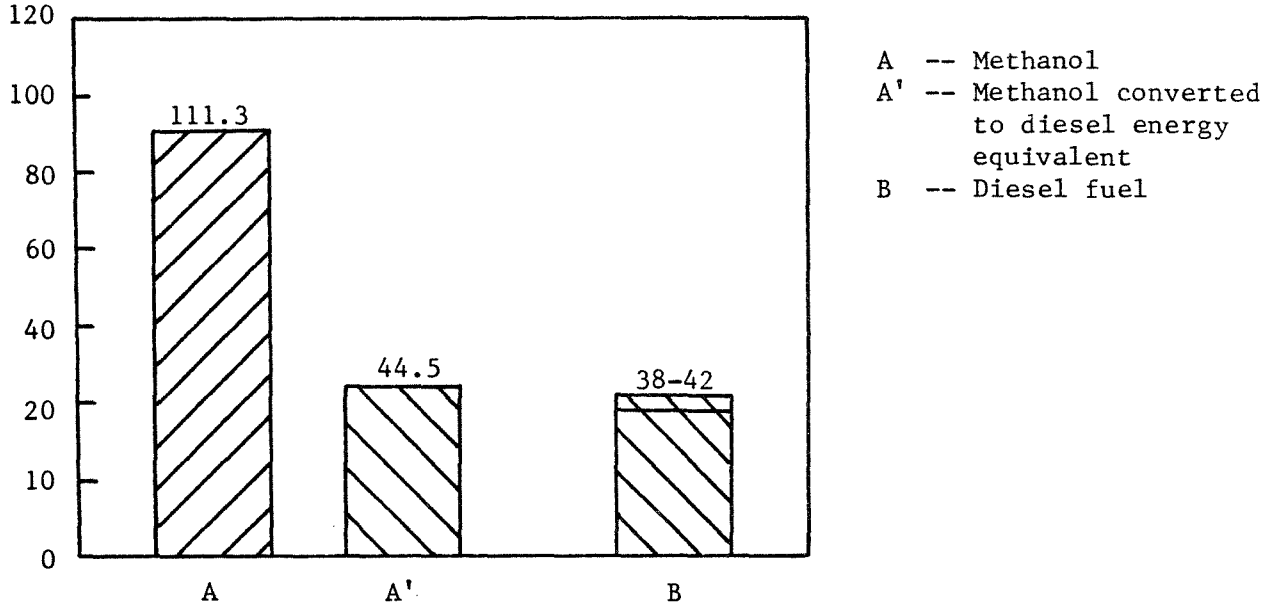


Figure 8-54. NEW ZEALAND'S PRELIMINARY RESULTS OF THE FUEL CONSUMPTION OF THE MERCEDES-BENZ M-407 hGO ENGINE (Ref. 53)

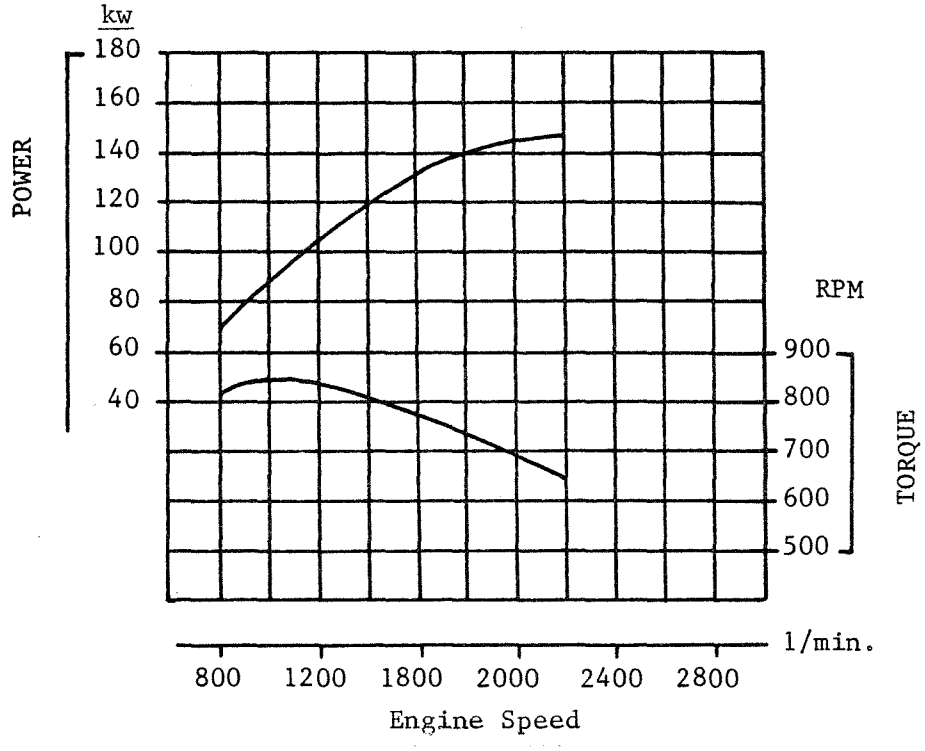


Figure 8-55. FULL-LOAD PERFORMANCE OF THE MERCEDES-BENZ M-407 hGO ENGINE (Ref. 53)

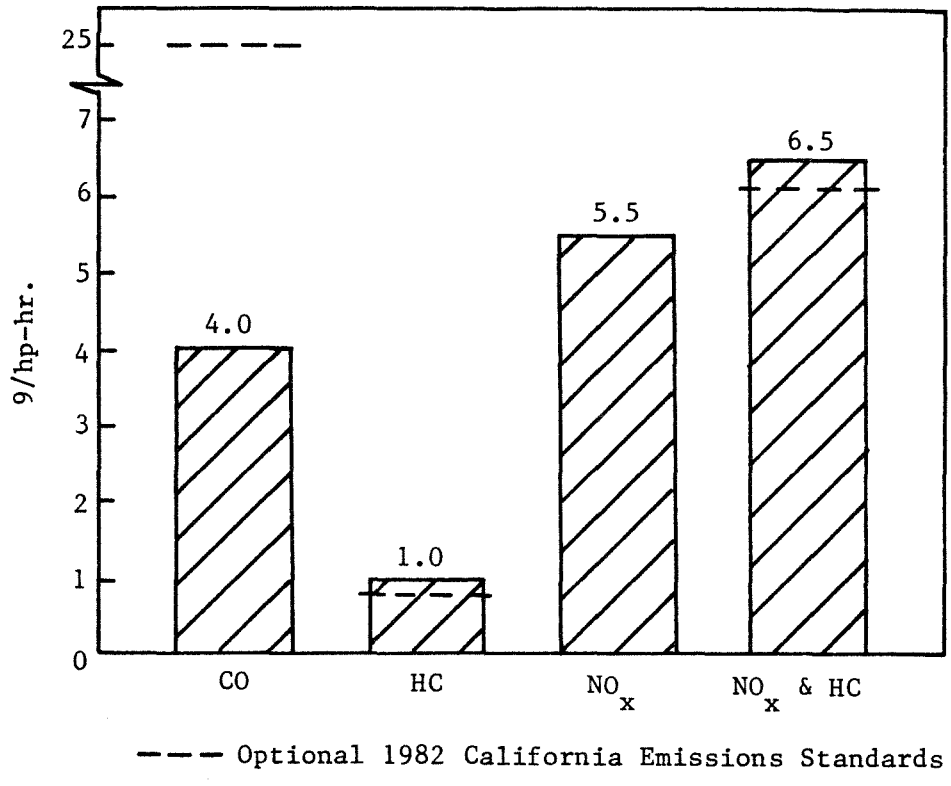


Figure 8-56. MERCEDES-BENZ RESULTS OF THE B-MODE FTP CYCLE EMISSIONS OF THE M-407 hGO ENGINE (Ref. 53)

The Mercedez-Benz methanol engine combines different technologies to produce an efficient power plant. The result is a complex system of standard and new equipment (such as the methanol vaporizer and cold start heaters) that are not readily applied to other systems. As a result, vehicle costs are predicted to differ greatly from existing diesel or LPG hardware. However, since this engine is still in the demonstration phase, cost information is not available.

Mercedez-Benz reports the advantages of their engine system as follows:

(1) High torque, efficiency, and performance.

(2) Low emissions (without catalyst)

(3) Incorporates energy recovery scheme.

5. Texaco Controlled-Combustion System Engine (Ref. 61 - 66)

a. TCCS Concept. The Texaco Controlled-Combustion System (TCCS) is a stratified charge combustion concept which controls the combustion by coordinating fuel injection, spark ignition, and air swirl. This results in a

lean fuel-air mixture which appears to provide improved fuel economy, low emissions, and lack of knock. The TCCS engine has been under development by Texaco since the 1940s. Although this engine has been developed for use on gasoline or "broad cut" fuel, it is possible to operate it with some modifications on methanol. Texaco has performed methanol testing with this engine.

In common with other direct injection stratified charge engines, the Texaco TCCS engine achieves its improvement in fuel economy over conventional throttled Otto-cycle engines through minimization of part-load intake manifold pumping losses by controlling engine power through fuel charge as opposed to air throttling. The stratified, but lean, fuel air mixture is able to tolerate higher compression ratios without preignition, and hence, provide higher thermal efficiencies. The TCCS engine uses a cupped piston design. During the intake stroke, the swirling airflow is created within the piston cup. The swirl velocity is then increased on compression as fuel is then injected. The fuel air mixture is then ignited by a long duration spark. This combustion sequence is presented in Figure 8-57.

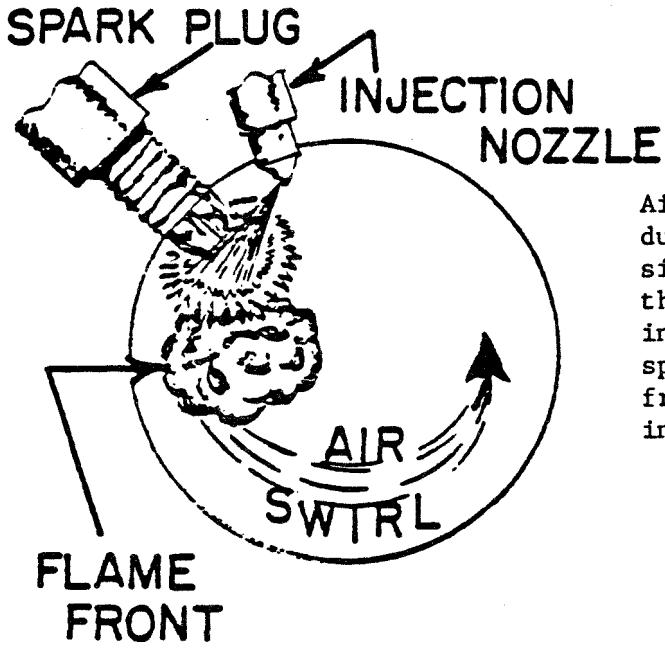
The TCCS concept has been implemented in a variety of engines and tested on a variety of fuels. The best known of these applications is the L-163S TCCS four-cylinder Army "jeep" engine and the adaptation of the 292 cubic inch General Motors engine. Typical performance and fuel efficiencies for the L-163S engine are presented in Tables 8-29 and 8-30. Likewise, typical performance for the UPS 292SC engine is presented in Figures 8-58 and 8-59, and Table 8-31.

In both cases, the engines provide efficiencies commensurate with that of diesel engines; although they are able to provide such efficiencies on a variety of fuels, including gasolines.

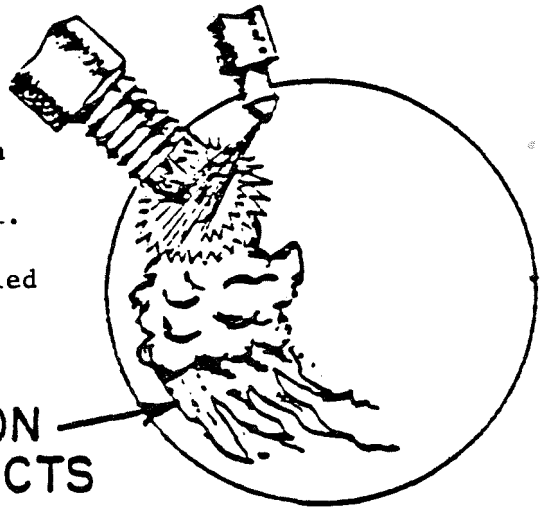
b. TCSS Operations on Methanol. A recent test program has been underway to examine the operation of the TCCS engine on methanol. The engine utilized has been the 163 cubic inch White engine. Figure 8-60 shows the fuel efficiency of the 163 engine on both methanol and gasoline. As can be seen, at lower engine speeds, the methanol engine had a higher output. Because of the size of the injection pump used in this test, the high-end output with the methanol engine was somewhat reduced over what would have been expected. Figure 8-61 shows the comparison between the UPS 292 engine operating on gasoline, and the L-163 engine operating on methanol. As can be seen from these figures, on an energy basis the brake specific fuel consumption the methanol engine is very close to that of the UPS 292 engine running on gasoline. In other words, one would expect that a methanol version of the 292 engine would provide fuel efficiencies on a Btu basis commensurate to that of a diesel engine of a similar size.

6. Conclusions

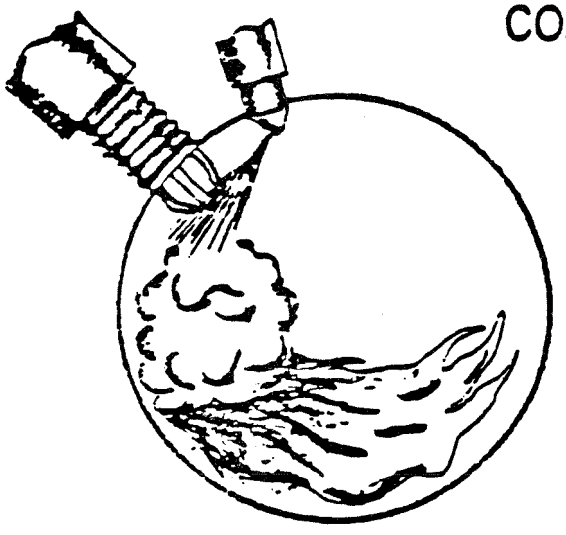
The M.A.N., Daimler Benz and Texaco engines operating on methanol, show thermal efficiencies very close to that of Diesel engines of similar size. For the M.A.N. engine, in some portions of its operating range, it has higher efficiency than for the diesel, and, in some portions, somewhat worse effi-



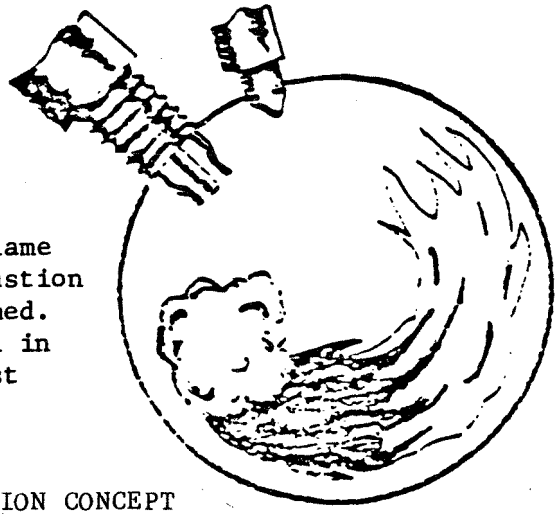
Air swirl, created by the intake port during the intake stroke, is intensified in a cupped piston design during the compression stroke. Combustion, initiated by fuel injection and positive spark ignition, establishes a flame front immediately downstream from the injection nozzle.



Spark continues; fuel is injected at a controlled rate; air continues to be supplied by the swirl to mix with fuel. The flame front is established and cylinder pressure builds at a controlled rate.



Spark is discontinued; fuel injection continues to mix fuel with air supplied by the swirl to feed the flame front.



Fuel injection is discontinued; flame front fades in intensity but combustion continues until all fuel is consumed. The result is a clean burn of fuel in a lean mixture yielding low exhaust emissions.

Figure 8-57. TCCS COMBUSTION CONCEPT (Ref. 53)

Table 8-29. L-163S TCCS VS. L-141 GASOLINE ACCELERATION COMPARISON
SWRI
WT. 3600 LBS

VEHICLE SPEED MPH	ACCELERATION TIME, SECONDS	
	L-141 (GASOLINE)	L-163S TCCS (DIESEL FUEL)
0 - 30	7.9	7.0
0 - 40	12.4	12.5
0 - 50	22.5	21.5

FUEL ECONOMY COMPARISON

VEHICLE SPEED MPH	FUEL ECONOMY, MPG		
	L-141 GASOLINE	L-163S TCCS	
		GASOLINE	DIESEL FUEL
20	24.1	33.1	36.2
30	21.3	29.2	31.9
40	18.6	25.2	27.7
50	16.0	21.2	23.5
IDLE	0.453 GAL/HR	0.179 GAL/HR	0.158 GAL/HR

Table 8-30. L-163S TCCS ENGINE/M-151 VEHICLE EXHAUST EMISSIONS
(1979 LIGHT DUTY TRUCK/FEDERAL TEST PROCEDURE)

2750 LB. INERTIA SETTING
DIESEL FUEL
EMISSION CONTROLS: EGR BUT NO CATALYST

	MASS EMISSIONS-B/MI.			FUEL ECONOMY (MPG)
	HC	CO	NO_x	
TEXACO TESTS 5 run avg.	1.5	13.2	1.3	25.3 (GRAY)
SWRI TESTS 3 run avg.	2.2	11.4	1.3	30.0(CBAL)
EMISSION CONTROLS: CATALYST + EGR				
TEXACO	1.0	1.4	1.4	26.6
SWRI	1.6	2.1	1.5	27.5
1979 LT.DTY TRUCK STDS.	1.7	18.0	2.3	

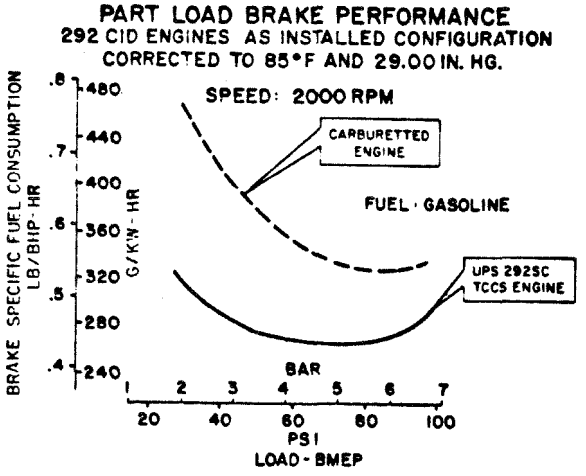
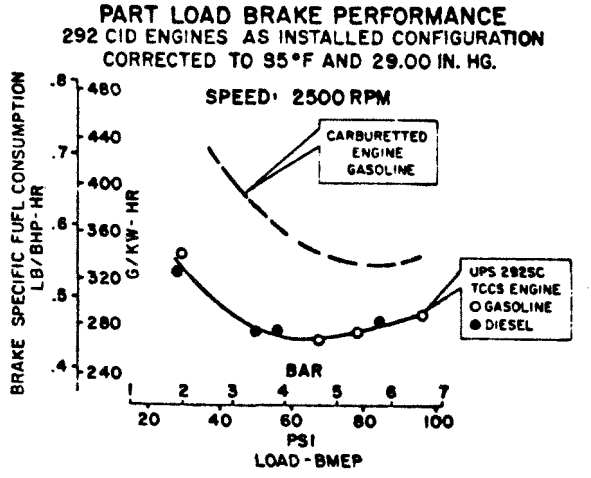


Figure 8-58a.
UPS 292 SC TCSS ENGINE PART LOAD BRAKE GASOLINE PERFORMANCE AT 2000 RPM (Ref. 53)

Figure 8-58b.
UPS 292 SC TCCS ENGINE PART LOAD BRAKE GASOLINE PERFORMANCE AT 2500 RPM (Ref. 53)



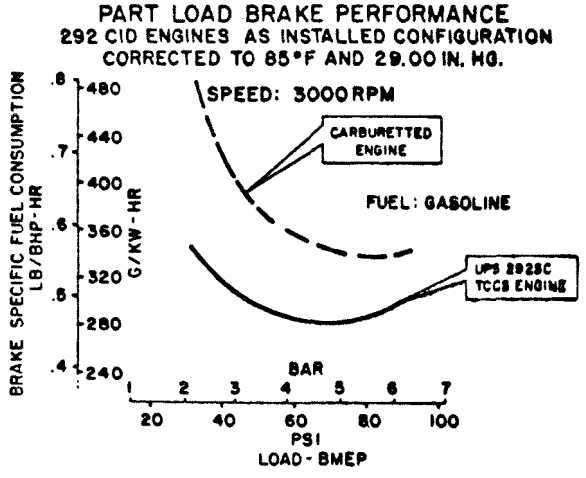


Figure 8-58c.
UPS 292 SC TCSS ENGINE PART LOAD BRAKE GASOLINE PERFORMANCE AT 3000 RPM (Ref. 53)

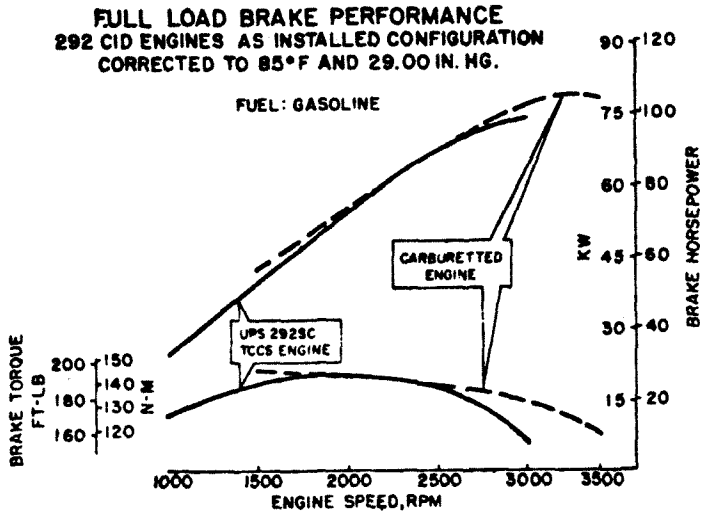


Figure 8-59. UPS 292-SC TCSS ENGINE FULL LOAD PERFORMANCE (Ref. 53)

Table 8-31. UPS-292 SC vs. GMC 292 FUEL ECONOMY COMPARISONS

	UPS 292 SC	GMC 292	PERCENT GAIN
ENGINE IDLE	.31 gal/hr	.75 gal/hr	142.0
CITY DRIVING TO/FROM DELIVERY AREA	9.4 mpg	7.2 mpg	30.6
ON AREA DELIVERY TEST CYCLE	8.7 mpg	6.3 mpg	38.1
HIGHWAY DRIVING ROLLING COUNTRY	10.3 mpg	8.6 mpg	19.8

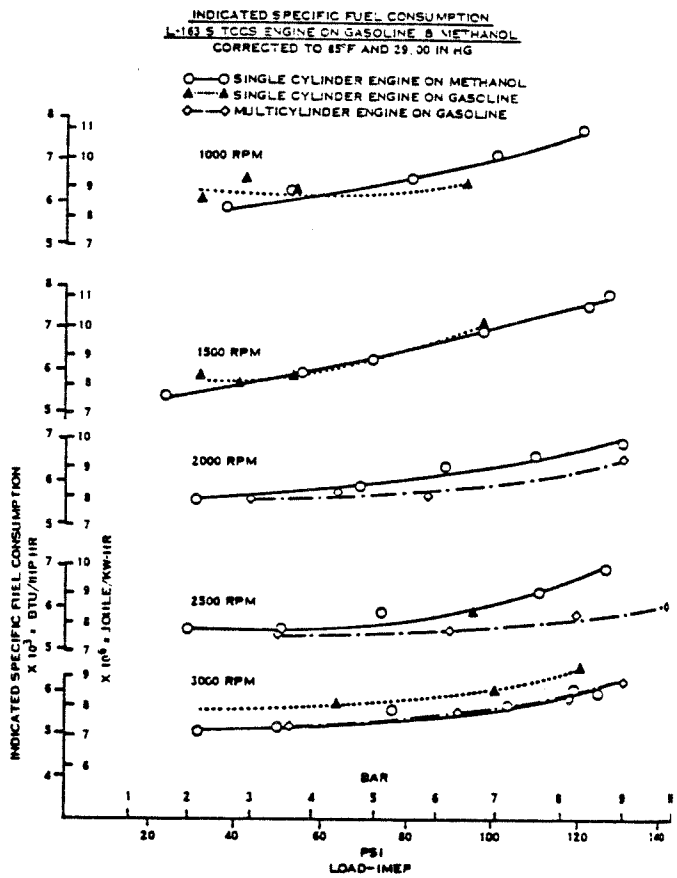


Figure 8-60. INDICATED SPECIFIC FUEL CONSUMPTION L-163S TCCS ENGINE ON GASOLINE AND METHANOL (Ref. 53)

ciency. However, the differences are relatively small. The New Zealand testing has shown approximately a 5 percent better energy efficiency with the methanol version of the engine. However, for other use profiles, the relative efficiencies between the diesel and the methanol versions may be different than this specific case. The Daimler Benz engine also shows efficiencies close to that of diesel, and, in some portions of its brake-specific fuel consumption map, a better efficiency than a diesel. However, New Zealand testing has yet to demonstrate this advantage. In fact, the fuel efficiency is 11 percent worse than the diesel.

To the extent this limited data permits generalization, it appears that the energy efficiency of the methanol medium-duty engine is very close (plus or minus perhaps 5 percent) of that of a diesel engine. If fuel operating costs were the only criteria in the selection of an engine, we would not

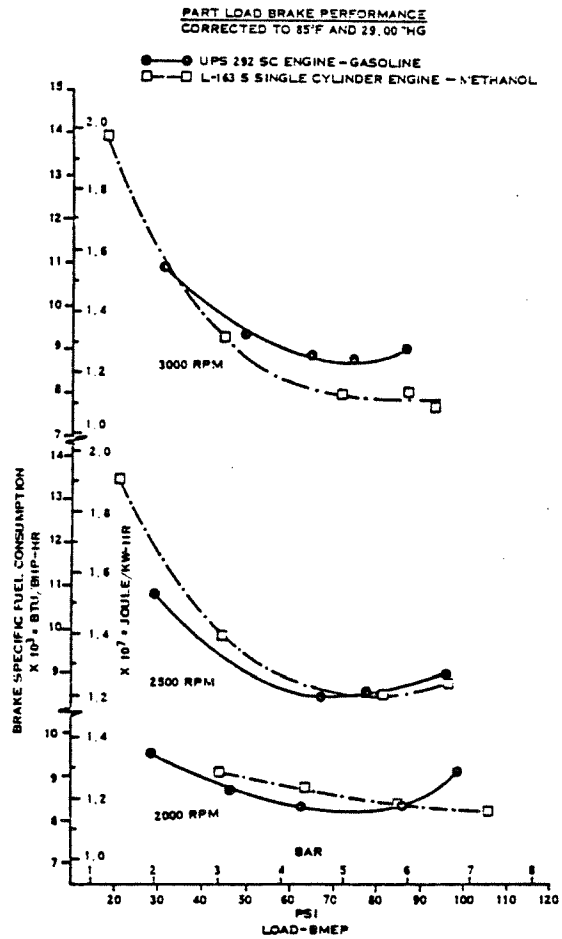


Figure 8-61. PART LOAD BRAKE PERFORMANCE UPS-292 SC GASOLINE AND L-163S SINGLE CYLINDER METHANOL (Ref. 53)

expect medium duty methanol engines to become marketplace competitive until the price of methanol achieved Btu price parity with diesel fuel.

The M.A.N. engine is based upon a diesel engine block and lower end, whereas the Daimler Benz engine is based upon an Otto block. In general, one would expect the diesel block to be somewhat more expensive to produce than the Otto block. However, the M.A.N. engine has a minimum of equipment added over the diesel engine, these being limited to basically ignition hardware. On the other hand, the Daimler Benz has a rather extensive set of hardware to affect preheating. Since neither engine is in production, the relative price

differential cannot be estimated between them. However, it appears both would be slightly more costly than a diesel engine.

To balance out this apparent increase in cost, both these engines do have certain advantages other than fuel efficiency. For example, both the M.A.N. and the Daimler Benz engine exhibit torque curves that appear to make them more attractive in transit operation than diesel engines. Secondly, there are areas of BSFC map where the engines are more efficient than diesel engines. Hence, if an operating profile can be matched to these differences, slightly larger fuel economy gains may be realizable. Lastly, since both are methanol engines, soot and particulates are not a problem.

E. FLEET SALES POTENTIAL FOR METHANOL VEHICLES

1. Background

Fleet sales have been proposed as one way to begin a transition to general sales of methanol-fueled vehicles. Presumably, the first sales will be to a subset of fleet buyers with the following characteristics:

(1) Vehicles are commonly retained for a considerable period of time, hence resale value is not of great concern.

(2) The vehicles are fueled on site or are fueled from a single contract source.

(3) The vehicle seldom, if ever, needs more than a 200 to 300 mile range between refuelings.

(4) Visibility/public relations, petroleum independence, or some other attribute of a methanol fuel is of value to the fleet operator.

The growing methanol-fueled fleets will then, it is believed, generate a growing retail distribution system which will in turn increase sales of methanol vehicles. However, such an approach, depending only upon market forces, may be ineffectual. There may exist enough fleet operators who value the attributes of methanol to generate a demand for methanol vehicles. The demand may be sufficient to interest a vehicle manufacturer in the production of methanol vehicles. The resultant demand for methanol fuel, however, may be far too small to cause a fuel supplier to establish retail capability in methanol.

2. Data Source

Since methanol vehicle market survey data for California or western fleets do not exist (at least in the public literature), the following analysis is based primarily on the fleet survey work done at Brookhaven National Laboratory for the Department of Energy in 1978 to 1980 (Refs. 67 - 75). Application of the BNL survey to California methanol fleet sales requires assumptions and inferences which cause conclusions to be speculative. Based upon the limited amount of applicable data, the following analysis attempts to provide information on:

(1) Potential size of the fleet market for which methanol vehicles may be appropriate.

(2) Characteristics of western vehicle fleets which limit or constrain potential methanol vehicle sales.

(3) The most likely types of fleets for methanol fleet sales.

(4) The possible amount of fuel methanol such sales would generate.

3. Fleet Vehicles - Western Region

California-specific survey and statistical data on fleet automobiles are not available. However, data are available on western regional fleet vehicles. The western region is defined as California, Oregon, Washington, Alaska, and Hawaii. If the stock of fleet automobiles is roughly proportional to the stock of total automobiles, one would expect 96 percent of western regional fleet vehicles to be in California, Oregon, and Washington, with California alone having 73 percent of the western regional fleet vehicles. In this analysis, a fleet will be taken to be 10 or more light duty vehicles.* The most useful publicly available survey of light-duty fleets in the U.S. was commissioned by the Department of Energy in 1978. Bobit Publishing Company (publishers of Automotive Fleet) under the direction of Brookhaven National Laboratory, surveyed the managers of light-duty vehicle fleets in the U.S. The survey data was stratified into six sectors:

(1) Police, both state and local.

(2) Government, both state and local, non-police.

(3) Taxi.

(4) Rental fleets.

(5) Utilities.

(6) Businesses.

The sample was also stratified into nine geographic regions.

Assuming that the western regional sample reflects the same sampling biases across sectors as the national sample, Table 8-32 presents an estimate of the automobile in fleets in the western region for 1978.

The Bobit/BNL survey also gathered data on light trucks. The survey questionnaires did not provide a quantitative definition of a light truck but did refer to them as pickups or vans. Given the estimate for the automobile stock presented in Column 1 of Table 8-32, an estimate for the stock of light trucks was made based on ratios by sector of light trucks to automobiles for the western region.

Ignoring sectorial growth and changes in purchasing behavior since 1978, the sectorial sales potential is derivable from the sectorial vehicle stock by using estimated capital turnover rates. The Bobit/BNL survey collected information from which the fraction of the fleets that are replaced annually is derivable. This is presented in Table 8-33.

* In comparing the results here with statistics used by other sources it should be recognized that the definition of a fleet is not uniform, some sources define a fleet as four or more vehicles, and some use four or ten total vehicles, including heavy-duty trucks and off-the-road construction and mining equipment.

Table 8-32. WESTERN REGIONAL FLEET POPULATION FOR 1978 BY SECTOR

SECTOR	AUTOMOBILES X 1000*	LIGHT TRUCKS x 1000**
POLICE	56.6	4.6
GOVERNMENT	126.3	44.4
UTILITIES	90.4	171.6
TAXI	17.7	1.9
RENTAL	18.3	3.3
BUSINESS	338.0	160.1
TOTAL	647.4	365.8

* This is based on Table 1 of Ref. 67 and the assumption that the ratio of survey vehicle/to vehicle national is applicable to the western region. While not confirmed, this assumption is supported by Fig. 3, Estimated Total Car Sales by Fleet Sector for 1978, of Ref. 69.

** Based on automobile stock from Table 1 of Ref. 67 and ratios by sector of light trucks to automobiles for western region in Table 4 of Ref. 68.

Table 8-33. WESTERN REGIONAL FLEET REPLACEMENT RATES*

SECTOR	AVERAGE ANNUAL MILES (x 1000)	REPLACEMENT AGE (Years)	AVERAGE REPLACEMENT MILEAGE (x 1000)	IMPLICIT ANNUAL MILES (x 1000)	FRACTION REPLACED PER YEAR
POLICE	32.7	2.60	62.9	24.2	0.385
GOVERNMENT	12.6	5.09	52.0	10.2	0.196
UTILITIES	11.4	6.35	65.1	10.3	0.157
TAXI	49.9	2.10	71.3	33.8	0.476
RENTAL	22.0	1.60	35.0	22.0	0.625
BUSINESS	22.5	2.52	51.7	27.8	0.397

*Based on Table 12.9 of Ref. 68.

The survey questions related to fleet replacement rates and capital turnover referred to vehicles and did not make a distinction between automobiles and light trucks. It will be, therefore, assumed that the replacement rates presented in Table 8-33 are applicable to light trucks. It should be noted that in fact light trucks remain in use longer than automobiles, depreciate more slowly, and accrue lower annual mileage. The application of Table 8-33 to automobiles may result in a underestimation on the automotive fleet turnover rate and, conversely, application to light trucks may result in a overestimation of the truck fleet turnover rate.

Applying these replacement rates to the fleet sizes given in Table 8-32, the estimated total car sales by fleet sector can be defined. Table 8-34 presents these estimated sales where annual sales = (fraction replaced per year) x (fleet size).

Two hundred and fifteen thousand vehicles per year for the western region or approximately 157,000 for California represent the potential market for methanol (or any other technology) fleet vehicle sales.

Based upon the estimated light truck stock and replacement rates, annual replacement sales by sector can be estimated. Fleet replacement rates in the Bobit/BNL survey appear to be for automobiles only. Since use patterns (annual mileage) is different for light trucks, a mileage replacement criteria would reduce sales. Sales estimates for both age and mileage replacement criteria are presented in Table 8-35. Of the 66,000 to 96,000 light truck sales per year into fleets, roughly 48,000 to 70,000 would be expected to

Table 8-34. ESTIMATED TOTAL CAR SALES BY FLEET SECTOR FOR 1978 IN WESTERN REGION

SECTOR	ANNUAL SALES (x 1000)
POLICE	21.8
GOVERNMENT	24.8
UTILITIES	14.2
TAXI	8.4
RENTAL	11.6
BUSINESS	134.2
TOTAL	215.0

Table 8-35. ESTIMATED TOTAL LIGHT TRUCK SALES BY FLEET SECTOR FOR WESTERN REGION

SECTOR	ANNUAL SALES x 1000 REPLACEMENT CRITERIA	
	Age	Mileage
POLICE	1.77	0.47
GOVERNMENT	8.723	4.50
UTILITIES	26.95	28.13
TAXI	0.90	0.36
RENTAL	2.07	1.76
BUSINESS	55.6	30.86
TOTAL	96.01	66.08

occur in California. Figure 8-62 presents a graphical comparison of sectorial stock and sales for the western region.

4. Factor Constraining Methanol Fleet Sales

A realistic estimate of sales is, of course, far smaller than the potential market size. Established purchase criteria, fleet buyer perceptions, and physical constraints will determine what fraction of the potential market is realizeable. To obtain a reliable estimate of methanol vehicle sale potentials, a methanol specific survey of fleet buyers is needed. The Bobit/BNL survey was not designed to assess the market potential of methanol vehicles. Therefore, the factors used from the Bobit/BNL survey should be viewed as imperfect surrogates for factors of a methanol survey. While the following analysis cannot be considered a sales forecast, it does provide some illumination of factors constraining methanol car sales.

Western fleet managers were surveyed on the criteria they used in making new car purchasers. The eight criteria surveyed were:

(1) Purchase price.

(2) Retail resale value (as a percent of original cost).

(3) Maintenance cost.

(4) Life-cycle cost.

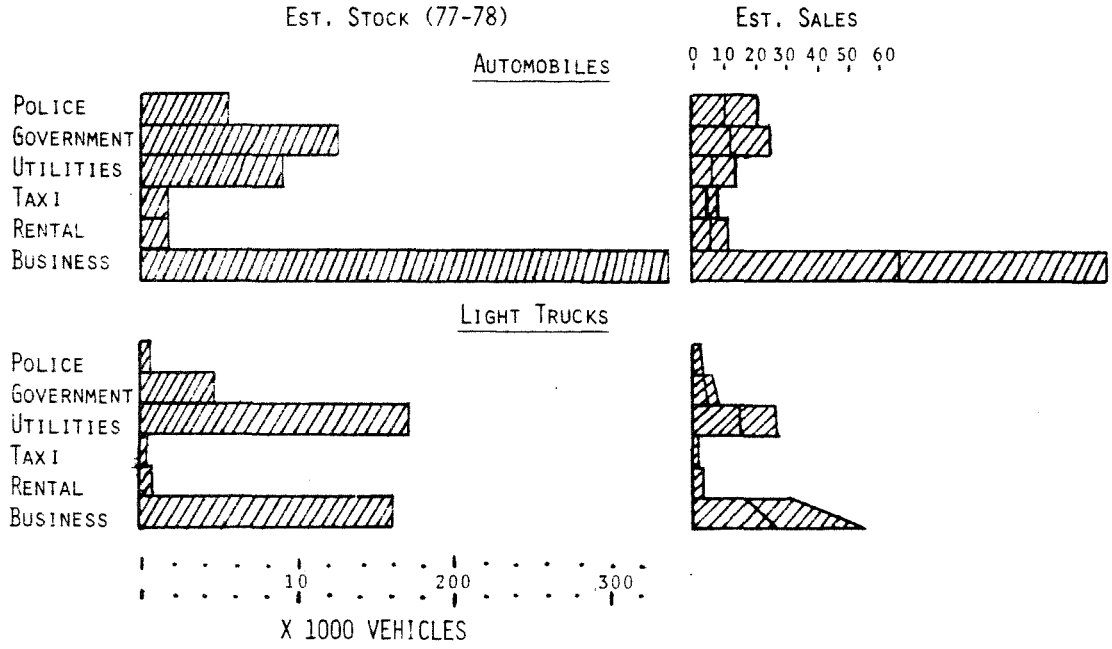


Figure 8-62. POPULATION AND SALES, WESTERN FLEET VEHICLES 1978

(5) Reliability (day-by-day).

(6) Running lifetime or durability.

(7) Tradition (i.e., past experience).

(8) Gas mileage.

The fleet managers were asked to rate each criteria on a scale of 1 to 5, five being most important, one being least important. Within each sector, the mean of the response for each criteria was computed. The four most important criteria (rank ordered by mean value) for each fleet sector is presented in Table 8-36.

Fleet vehicles are resold (usually through an intermediary) to households. On the "leading edge" of a methanol transition, the blue book value on methanol-fueled cars will be unspecified at best, virtually worthless at worst. The rental car market and the taxi fleet market specified resale

Table 8-36. PURCHASE CRITERIA*

POLICE	Reliability	3.84	TAXI	Resale	3.17
	Maintenance	2.99		Life-Cycle Cost	2.51
	Gas Mileage	2.80		Purchase Price	2.46
	Resale	2.27		Reliability	2.14
GOVERNMENT	Purchase Price	4.56	RENTAL	Resale	4.53
	Gas Mileage	4.36		Reliability	3.78
	Reliability	3.71		Maint. Cost	3.64
	Running Life	3.67		Gas Mileage	3.46
UTILITY	Gas Mileage	4.17	BUSINESS	Reliability	3.76
	Purchase Price	3.44		Main. Cost	3.65
	Maint. Cost	3.04		Purchase Price	3.47
	Reliability	2.90		Resale/gas mi.	3.43

*Based on Table 2.9 of Ref. 68.

value as the most important of the purchasing criteria. Initial sales of methanol cars into these sectors are, therefore, taken to be nil. For the resale criteria to have a mean value of 3.43 on a scale of one to five implies that a large proportion of the business fleet managers must judge resale to be an important criteria. Until a more detailed survey can be made, it will be assumed that the resale criteria rules out one-half of the potential sales to business fleets. For the police, governmental, and utility sectors, resale ranked low on the purchase criteria and reliability ranked high as did gas mileage. To the extent that reliability can be associated with availability during petroleum crises and gas mileage can be associated with concern over unanticipated escalation in petroleum product prices, these criteria favor methanol in the police, government, and utility sectors.

Purchase criteria is not the only constraining factor on methanol vehicle sales to fleet operators. Three other factors in the Bobit/BNL survey have a direct bearing on the western regional market potential for methanol fleet sales. The fleet operators were surveyed to determine if they felt that diesel fuel was sufficiently available for them to consider diesel engine cars as an option. If a fleet purchaser did not believe that diesel was sufficiently available in 1977, it is unlikely he would look favorably on the methanol for a considerable length of time. Hence, we will keep as candidate methanol vehicle purchasers only those who felt that diesel was adequately available for their utilization in 1977. Due to the initial thin fuel supply system, it is unlikely that methanol-fueled vehicles would be used for anything other than local trips. The fleet operators were also surveyed to determine what percent of their vehicles could tolerate a distance between refueling of 150 miles or less. Utilizing the response to this question as a surrogate for local trip capability, we can delete from potential methanol

vehicle sales those vehicles that must have long distance capability. It is unlikely that methanol vehicle fleet purchasers would occur in the smaller fleets. The larger fleet operators have much greater capability, expertise, and resources to deal with an alternatively-fueled vehicle. Large fleets also have the potential to use specific vehicles for specific purposes (e.g., a methanol pickup only for short local trips). Fortunately, almost all fleet vehicles in the western region are operated by large fleet operators, with the sole exception of taxi fleets, which are relatively small. Table 8-37 presents by sector the factors that constrain initial methanol automobile sales.

The criteria used in making light truck purchases by fleet managers was not separately surveyed by Bobit/BNL. It will be assumed that the criteria rankings for automobiles are also applicable to light trucks. The three other factors (large fleets, diesel availability, local utilization) used in estimating methanol automobiles sales potential were separately estimated for light trucks within the survey. These factors constraining initial sales of methanol vehicles are presented in Table 8-38.

It should be noted that there are significant differences between automobiles and light trucks in terms of these three factors. Most light trucks within taxi fleets are found in the larger fleets. This is quite unlike taxi automobiles. Diesel availability was found to be much less of a limiting factor for trucks than automobiles for all sectors. With the exception of utilities and rental trucks, light trucks are used for local short trips more than automobiles are used. Figure 8-63 presents a comparison of the factors by sector.

Table 8-37. FACTORS CONSTRAINING SALES OF METHANOL AUTOMOBILES IN THE WESTERN REGION*

SECTOR	I FRACTION IN LARGE (200+) FLEETS	II FRACTION DIESEL AVAILABILITY WAS ADEQUATE	III FRACTION SHORT TRIPS ONLY (less than 150 mi)	IV RESALE CRITERIA (see text)
POLICE	0.929	0.098	0.065	1.0
GOVERNMENT	0.048	0.391	0.236	1.0
UTILITIES	0.917	0.536	0.440	1.0
TAXI	0.130	0.376	0.824	0.0
RENTAL	0.935	0.178	0.563	0.0
BUSINESS	0.846	0.255	0.155	0.5

*Based upon Tables 5.1, 6.9, 2.9, from Ref. 68; and 3.12b from Ref. 67.

Table 8-38. FACTORS CONSTRAINING INITIAL SALES OF METHANOL-FUELD LIGHT TRUCKS

SECTOR	I FRACTION IN LARGE (200+) FLEETS	II FRACTION DIESEL AVAILABILITY WAS ADEQUATE	III FRACTION SHORT TRIPS ONLY (less than 150 mi)	IV RESALE CRITERIA (see text)
POLICE	0.757	0.568	0.477	1.0
GOVERNMENT	0.887	0.540	0.479	1.0
UTILITIES	0.910	0.843	0.354	1.0
TAXI	0.651	0	1.00	0.0
RENTAL	0.921	0.742	0.220	0.0
BUSINESS	0.872	0.918	0.622	0.5

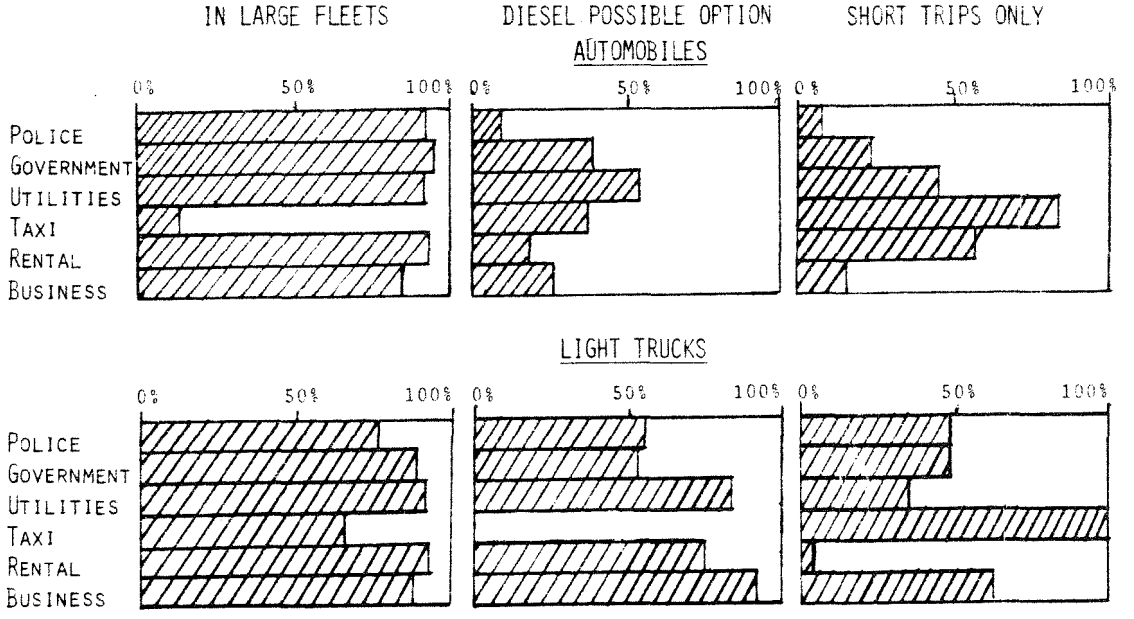


Figure 8-63. FACTORS CONSTRAINING INITIAL SALE OF METHANOL VEHICLES

5. Possible Fleet Sales Volumes

Assuming these factors are independent, the estimated methanol fleet vehicle initial annual sales can be calculated for each sector. This should not be considered as a sales forecast but rather as a subjective assessment of how the various constraints reduce the potential market. This is presented in Table 8-39.

The results of this analysis yield an initial sustained sales of approximately 5750 methanol-fueled vehicles in the western region in the initial years of methanol introduction. This would imply a sales expectation of approximately 4,000 vehicles in the State of California. If only the criteria of diesel fuel availability is used to estimate the expected market, a western regional sales expectation of about 36,500 vehicles per year is obtained. If only the lesser of the diesel fuel criteria or the short trip capability criteria (but not both) is used, a western regional sales expectation of about 24,000 vehicles per year is obtained.

The difference in these factors between automobiles and light trucks results in the light truck market being more attractive for methanol vehicles than the automotive market. Utilizing these factors in the same manner as for automobiles results in an estimated initial annual sales volume for light trucks. This is presented in Table 8-40. The range of estimates represents the uncertainty between age and mileage as the replacement criteria for light trucks in the various sectors.

Based upon these criteria, the sales potential in light trucks is between five times to two times larger than the sales volume for automobiles. As was the case with automobiles, light truck sales appear to be dominated by the larger business fleets and the utilities markets. Figure 8-64 presents a comparison of truck and automobile potential by sector.

Table 8-39. AUTOMOBILES PER YEAR
(Possible Methanol car sales x 1000)*

SECTOR	SALES LIMITING FACTORS FROM TABLE 8-25		
	I+II+III+IV	I+II+IV	I+IV+(II or III)
POLICE	0.13	2.13	1.42
GOVERNMENT	0.22	9.68	5.84
UTILITIES	3.07	7.60	6.24
TAXI	0	0	0
RENTAL	0	0	0
BUSINESS	2.24	17.11	10.40
TOTAL	5.7	36.5	23.9

* For example: 21.8K*(0.929*0.065*1.0) = 0.13K for the police sector in column 1.

Table 8-40. ANNUAL METHANOL LIGHT TRUCT SALES

SECTOR	SALES LIMITING FACTORS FROM TABLE 8-38		
	I+II+III+IV (x 1000)	I+II+IV (x 1000)	I+IV+(II or III) (x 1000)
POLICE	0.36-0.10	0.76- 0.20	0.76- 0.20
GOVERNMENT	2.00-1.03	4.18- 2.16	4.18- 2.16
UTILITIES	7.33-7.65	20.67-21.58	20.67-21.58
TAXI	0	0	0
RENTAL	0	0	0
BUSINESS	13.84-7.68	22.65-12.57	22.65-12.51
TOTAL	23.5 -16.5	48.25-36.5	48.25-36.5

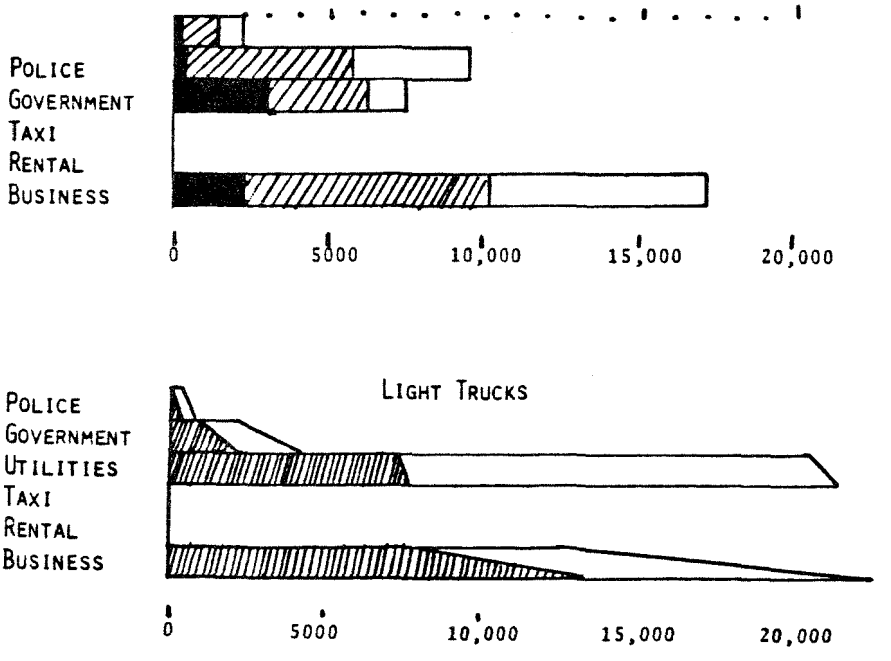


Figure 8-64. POSSIBLE SALES VOLUMES FOR METHANOL VEHICLES

These figures represent average sustained sales. If a major fleet operator in any sector decided to replace a large fraction of his fleet with methanol-fueled vehicles, these figures could be significantly exceeded for that year. The purchase criteria used in this analysis is clearly nonexhaustive. Many other factors can enter in a methanol vehicle purchase decision. The government sector, in particular, could choose to purchase methanol-fueled vehicles based upon perceptions of societal or environmental factors.

6. Possible Methanol Demand from Fleet Markets

The demand for methanol fuel will be determined by the stock of methanol cars which in turn is determined by the rate of sales and rate of retirement of such vehicles. While a sales forecast of methanol cars has not been made in this analysis, the lower estimate from Tables 8-39 and 8-40 will be assumed to calculate methanol fuel demand.

Gasoline consumption for the western fleet vehicles can be calculated fom the stock in each sector, composition of the stock, and estimated mileage. Table 8-41 presents the distribution of vehicle size within each of the sectors, along with the associated 1977 fleet-weighted over-the-road fuel economy for each sector (Ref. 76).

Table 8-42 presents the estimated annual miles per vehicle and the total vehicle miles traveled for each sector along with the resulting consumption of

Table 8-41. SIZE DISTRIBUTION AND FLEET FUEL ECONOMY FOR WESTERN AUTOMOBILE FLEETS*

	SIZE DISTRIBUTION			OVER-THE-ROAD FLEET WEIGHTED FUEL ECONOMY (MPG)
	SMALL	MIDSIZE	LARGE	
POLICE	0.004	0.082	0.914	16.3
GOVERNMENT	0.096	0.365	0.539	17.1
UTILITY	0.035	0.705	0.260	17.4
TAXI	0.006	0.062	0.932	16.2
RENTAL	0.324	0.420	0.256	18.3
BUSINESS	0.047	0.326	0.627	16.8
EPA CITY HIGHWAY (MPG)	26.9	22.0	19.6	

* Based upon size distribution for Tables 1.1a or 1.6b of Ref. 68, EPA CITY mpg from Table 2.4, 2.5 of Ref. 67), and EPA to over-the-road correction factor for 1977 from Pg. 2-12, Ref. 77.

Table 8-42. VEHICLE MILES TRAVELED AND FUEL CONSUMPTION FOR WESTERN REGIONAL FLEET VHEICLES

SECTOR	ANNUAL MILES PER VEHICLE (x 10^3 miles)	VEHICLE MILES TRAVELED (10^9 miles)	FUEL CONSUMPTION (x 10^6 gallons)
POLICE	32.7	1.85	113
GOVERNMENT	12.6	1.59	93
UTILITIES	11.4	1.03	59
TAXI	44.9	0.79	49
RENTAL	22.0	0.41	22
BUSINESS	22.5	7.61	450
TOTAL		8.81	786

gasoline. The vehicle miles traveled and fuel consumption for these sectors is approximately 4-1/2 percent of the totals for the western region. 1977 fuel use should be viewed only as a "bench mark" because fuel efficiencies will be significantly higher in 1986. After the gasoline and methanol vehicles reach market equilibrium in each sector based upon the assumed yearly sales, the demand for methanol fuel can be calculated. The annual methanol consumption is presented in Tables 8-43 and 8-44.

As was the case with automobiles, the demand for methanol fuel for light truck fleets will be estimated from the lower sales estimate from Table 8-40. Unlike automobiles, size distribution for light trucks across the various sectors is not available. Hence, it will be assumed that the over-the-road average fuel economy for light trucks is 11 miles per gallon.

Table 8-45 presents the estimated annual miles per vehicle and total vehicle miles traveled, along with a resulting estimated gasoline consumption for light trucks.

The annual miles traveled per vehicle were estimated as follows. The 1977 U.S. Department of Transportation Truck Inventory and Use Survey (TIUS) provided annual miles driven for several economic sectors. The government, utility, and rental fleets were covered in that survey. The police sector was assumed to have a light truck utilization similar to other government sectors, hence the government estimator from the TIUS was used. TIUS did not contain a taxi sector but did contain a for-hire truck sector which was used as a surrogate. The business sector was composed of several different subsectors so an average of 15,000 miles per year per vehicle was used. The national average light truck statistics were scaled to the western regional statistics by utilizing the ratio of the western regional to national annual miles for automobiles. (From BNL/Bobit Survey.) This assumes that the use differences

Table 8-43. POSSIBLE METHANOL DEMAND--AUTOMOBILES

SECTOR	METHANOL DEMAND (Gallons x 10^6 per year)
POLICE	1.1
GOVERNMENT	1.3
UTILITIES	20.4
TAXI	0
RENTAL	0
BUSINESS	12.0
TOTAL	34.8

Table 8-44. POSSIBLE METHANOL DEMAND--LIGHT TRUCKS

SECTOR	METHANOL DEMAND (Gallons x 10^6 per year)
POLICE	0.7
GOVERNMENT	5.8
UTILITIES	50.5
TAXI	0
RENTAL	0
BUSINESS	41.3
TOTAL	98.3

between the western region and the nation as for light trucks are similar to the use differences for automobiles.

After the gasoline and methanol vehicles reach market equilibrium in each sector based upon the assumed yearly sales (2.7 percent of sales ultimately results in 2.7 percent methanol vehicle population), the demand for methanol fuel can be calculated. The annual methanol consumption is calculated in Table 8-45.

Table 8-45. LIGHT TRUCK MILES TRAVELED AND FUEL CONSUMPTION FOR WESTERN REGIONAL FLEET VHEICLES

SECTOR	ANNUAL MILES PER VEHICLE (x 10^3 miles)	VEHICLE MILES TRAVELED (10^9 miles)	FUEL CONSUMPTION (x 10^6 gallons)
POLICE	8.7	.04	3.6
GOVERNMENT	6.5	.28	25.5
UTILITIES	11.9	2.04	185.5
TAXI	19.8	.038	3.5
RENTAL	18.7	.068	6.2
BUSINESS	12.5	1.825	166.0
TOTAL		4.29	390.3

The resulting demand for methanol represents approximately 0.2 of 1 percent of the gasoline consumed in the western region. Such a number is extremely small compared to petroleum products that are distributed by major oil companies. It is very unlikely that such a small demand would engender interest in establishing a supplier distribution system from a major company. From another perspective, the resultant methanol demand is approximately equivalent to the pumping rate of 70 conventional service stations.

In a analogous manner to the estimate for automobiles, the lower of the sales estimates for methanol light trucks was used to estimate final demand of methanol in gallons per year (Table 8-44).

As can be seen from the table, the differing purchase constraints and use factors between automobiles and light trucks lead to an appreciably larger demand for methanol fuel from the light truck fleets as opposed to the automobile fleets. These estimates can be viewed as an upper bound for methanol demand from fleets until such time as the methanol distribution system becomes developed. Taken together, this demand is equivalent to about 1200 tons per day of methanol production, or about 1/3 of the capacity of a remote natural gas plant.

F. SUMMARY OF POTENTIAL METHANOL DEMAND IN CALIFORNIA TRANSPORTATION SUBMARKETS

The total future demand for methanol in California in the transportation sector will be in agregation of the demands generated by various submarkets. The various submarkets that have been examined in this analysis include gasoline and methanol blends, private passenger neat methanol fueled vehicles, neat fueled light-duty fleets, and finally, medium- and heavy-duty applications of methanol fueled engines. The following paragraphs briefly summarize the results of the previous technical analyses as they apply to the potential demand for methanol.

1. Methanol Demand in Refining and Blending Submarkets

There exist two principal applications of methanol within these submarkets. First is the use of methanol as one of the feedstocks in the production of MBTE, the second is its use with a co-solvent in gasoline blending. California demand for methanol for use as a feedstock to MBTE production will be very small or non-existent. This is due to the absence in California of high concentration, high volume sources of isobutylene feedstocks. If a major petrochemical industry develops in California comparable to that found along the Gulf Coast, this situation could change.

There will exist a small market for methanol as a gasoline blending agent by the smaller (topping and hydro-skimming) refineries. This market appears to be presently existent at current methanol prices but mainly unsatified. However, the fraction of gasoline produced in California by such refineries is quite small (approximately 4 percent). For some of these refineries, octane number barrel costs may be sufficiently high to justify the use of high-priced co-solvents such as propanols if low-priced tertiary butyl alcohol is not readily available. For the most part, however, it will be the availability of relatively low-price tertiary butyl alcohol on the West Coast that will determine the magnitude of use of methanol as a blending agent in California. If all of the TBA produced in the United States were shipped to the California markets, approximately 70 percent of the gasoline produced in California could be blended with methanol. The most likely application of methanol TBA in California would be in the blending of higher octane unleaded gasolines by the larger refineries or by upgrading regular grade to premium grade by blenders or small refineries. Unless the front-end volatility of the gasoline into which it is blended is reduced, RVP limits may be exceeded and/or driveability may suffer. Since the small gasoline blender has little control over the front-end volatility of the gasoline he recieves, this reduces the potential market. For the larger refineries, there is the potential to "back out" butane and reduce volatility, however, it may not be an economic solution to providing octane if the refinery's existing octane number of barrel cost is low. Compared to the production of a remote natural gas based methanol plant of approximately 3,000 tons per day, the potential demand from the blending in the refinery sector in California is rather small. For example, if we assume that 20 percent is a reasonable estimate for the amount of gasoline that could potentially be blended with methanol, the daily methanol demand is approximately 900 tons of methanol or a little less than than one-third of a single plant's capacity.

2. Methanol Fuel Demand from Private Passenger Vehicle

Methanol-fueled vehicles appear to have attributes similar to gasoline-fueled vehicles. Such vehicles could be built performance-equivalent, or perhaps superior, to gasoline-fueled vehicles, and the tailpipe emissions are of a nature that could lead to improvements in urban air quality as described in Chapter 6. Furthermore, the methanol-fueled vehicle appears to have a thermal efficiency advantage over that of a gasoline-fueled vehicle. The basic question appears to be: is the thermal efficiency advantage sufficient to overcome the relatively high methanol price? The answer to such a question is more dependent upon the petroleum price scenario that is chosen than it is upon the uncertainties in the efficiencies of methanol versus gasoline vehicles. Therefore, methanol vehicle viability will be briefly outlined in terms of the three scenarios used in this analysis.

a. Low Petroleum Price Scenario. Under the low petroleum price scenario, liquid methanol-fueled vehicles do not achieve over-the-road cost competitiveness with gasoline-fueled vehicles in the foreseeable future. This is true for both remote natural gas-based methanol and coal-based methanol. Dissociated methanol-fueled vehicles become cost-competitive with gasoline in the early 1990s if the source of the methanol is remote natural gas. However, even with dissociated methanol technology, coal-based methanol does not become competitive in the foreseeable future.

b. Baseline Petroleum Price Scenario. Using the baseline petroleum price scenario, liquid methanol-fueled vehicles become competitive with gasoline vehicles around the year 1990 if the methanol is assumed to be derived from remote natural gas. The competitive advantage in over-the-road costs after the early 1990s is not dramatic. This implies a relative modest growth rate in the methanol vehicle market. Dissociated methanol technology would move the breakeven date forward by several years, but more importantly, would significantly increase the cost advantage of methanol relative to gasoline. Under this baseline petroleum price scenario, coal-based methanol would not be competitive with gasoline in the foreseeable future even with dissociated methanol vehicle technology.

c. High Petroleum Price Scenario. Under the high petroleum price scenario, methanol-fueled vehicles would become competitive with gasoline vehicles in the late 1980s and after this time possess a significant cost advantage relative to gasoline. The high oil price scenario combined with dissociated methanol technology would permit coal-based methanol to be competitive with gasoline in the early 1990s.

In summary, it appears that coal-based methanol is far too expensive to become cost competitive with gasoline before the year 2000. If the source of methanol is remote natural gas, it appears that methanol-fueled vehicles could be competitive with gasoline-fueled vehicles in the 1990s, but the size of the cost advantage for the methanol-fueled vehicles versus the gasoline-fueled

vehicles is far more dependent upon the behavior of future petroleum prices than it is on the efficiencies of the methanol engines.

3. Medium- and Heavy-Duty Applications of Methanol Engines--Trucks and Buses

There exist several methanol medium- and heavy-duty engines that are close to being commercially available. Several of these engines have been road tested, both in New Zealand and Germany. The UPS Texaco TCCS engine was originally designed to run on conventional fuels, but has been demonstrated to function satifactory on methanol.

Based upon the road test work to date, there does not appear to be a significant efficiency advantage of methanol vehicles over diesel vehicles in medium- and heavy-duty applications. This implies that no significant market would be expected to develop until methanol and diesel reach approximately parity in the price per Btu. Under the baseline petroleum price scenario, Btu parity with distillate oils is not reached by low price remote natural gas based methanol until well after the year 2000.

4. Near-Term Ligh-Duty Fleet Vehicles

There now exists a very small methanol market in commerical fleet vehicles supported by several small companies performing vehicle conversions to neat methanol. If quality methanol vehicles were available and the price of methanol fuel was such that these vehicles would have an over-the-road cost competitiveness with gasoline, the near-term potential market is probably still limited to between four and ten thousand vehicle sales per year. This is due to constraining factors such as uncertainty on resale value, ready availability of methanol fuel, and customary maximum trip lengths for the vehicles. If methanol vehicles were in fact sold at this volume, it would imply an increase in methanol demand of between about 20 and 75 tons of methanol per day. Such a volume is quite small in comparison to a remote natural gas methanol plant size of between two and four thousand tons per day.

5. Summary

In summary, the most likely near-term generator of methanol demand in California is methanol gasoline blends. The principal constraint on this market is the California availability of low-priced co-solvents, not the price of methanol itself. Neither medium- and heavy-duty trucks or buses, or light-duty commercial fleets appear to possess the potential for generating significant near- to mid-term methanol demand. Neat methanol-fueled private passenger vehicles appear to become over-the-road cost competitive with gasoline vehicles in the early 1990s. A modest growth rate in this market probably would not overstress the remote natural gas-based methanol resource potential. If 10,000 methanol vehicles were added in California, this would generate approximately 50 to 75 tons per day of methanol demand. Such a growth rate should be compatible with a modest increase in remote natural gas methanol capacity.

G. CONCEPTS FOR FURTHER ANALYSIS

In an analysis such as the California Methanol Assessment, the depth of the detailed analysis is, of necessity, sacrificed somewhat by the requisite breadth of the scope of the study. Within the market sectors of methanol blends, private passenger cars, and fleet vehicles there are areas which may be deserving of further inquiry. The major results of such further inquiries would be a refinement of the size and timing of the expected methanol demand. Within each of these areas, a market research activity may be warranted to more precisely determine the expected behavior of methanol in the marketplace. This subsection provides an outline of these market research activities in the above three areas.

The analysis of the potential demand for methanol by fleet vehicles in California was based, in part, upon a 4-year old fleet buyer's survey conducted by Brookhaven National Laboratories and Bobbit Publications for the Department of Energy. The survey was designed to address market questions relating to electric and hybrid vehicles. The understanding of the market for methanol vehicles in California fleets can be refined and improved by a similar survey, oriented specifically toward methanol-powered vehicles in California. Such an analysis should be performed by a firm specializing in automotive market analysis with experience in the analysis of the fleet vehicle market in California. A fleet buyer's market research study for methanol vehicles should be stratified by market sector and be focused upon the value and liabilities in the marketplace of the attributes of methanol vehicles. The effects upon the value of methanol vehicles of resale price and ready availability of methanol fuel should be specifically examined. Such an analysis would be useful to state planners in further extensions of the California methanol fleet activities and, additionally, to automotive companies and energy companies in efficiently planning for possible methanol introduction.

The economic potential of methanol blended into gasoline was examined in this study with a simple model which was sensitive to octane number, cost, and vapor pressure. In reality, the economics of refinery operations for gasoline blending are far more complicated than described in this simple model. To obtain a better estimate of the economic potential of methanol in this market sector a refinery balance and cost linear programming analysis should be done.

Such an analysis would best be performed by a firm specializing in technical and management consulting to the California refinery industry that has in-house capability in refinery balance and cost/economic linear programming models and a database representative of California-specific refineries, including crude slates and product mixes. Due to the small available quantity of inexpensive co-solvent (TBA), such an analysis should examine the tradeoff of various concentrations of co-solvent and parametrically examine the gasoline methanol price combinations that would present other more expensive co-solvents to enter the marketplace. In addition, such a refinery analysis should be sensitive to the seasonal nature of vapor pressure restrictions on the gasoline to examine if methanol blends are a seasonal product. The analysis should also be sensitive to the constraints imposed by Section 211F of the Clean Air Act and the phase separation

constraints driven by temperature and water present in the refinery system. The results of such an analysis would permit both state and corporate planners to better assess magnitude and timing of potential methanol demands and the relationships generated in other market sectors.

The methanol demand generated by private passenger vehicles was estimated in this analysis by using the surrogate of over-the-road variable cost for marketplace viability and using analogies to diesel vehicles for a potential introduction rate. In fact, the automotive market is far more complicated than that represented by such a simple estimating procedure. Uncertainty in this largest potential sector can assuredly be reduced by a market research activity focused upon methanol vehicles. Such a market research activity would be best performed by a recognized market research firm specializing in automotive market analysis and sensitive to the California marketplace. To most effectively conduct a market research activity, some prior data and information would need to be developed. This would include a complete description of the consumer perceptible attributes of several methanol-fueled vehicles or, preferably, several methanol vehicles that could be used for the market research activity. Additionally, sufficient information to properly educate the participants in the market research is necessary because the characteristics of methanol vehicles are not well known by the general public. The objectives of a methanol vehicle market research activity in California would include:

(1) Identifying early markets for methanol vehicles by market sector, value within the market sector, and potential size of the market.
(2) Identifying the most market viable types of methanol vehicles.

(3) Quantifying the relationships of various factors that can influence the market viability of the methanol vehicles, including methanol price vs. gasoline price and the market viability impact of the size of the methanol supply infrastructure.

The results of such an analysis would permit a better estimate of the potential timing and magnitude of methanol demand and, therefore, the potential impact upon air quality and other factors.

H. REFERENCES

1. Wigg, E. E. and Lunt, R. S., "Methanol as a Gasoline Extender - Fuel Economy, Emission and High Temperature Driveability," SAE 741008, published in Alcohols as Motor Fuels, 1980.

2. Ingamells, J. C. and Lindquist, R. H., "Methanol as a Motor Fuel or a Gasoline Blending Component," SAE 750123, published in Alcohols as Motor Fuels, 1980.

3. Keller, J. L., et al., Methanol Fuel Modification for Highway Vehicle Use - Final Report, report for DOE under Contract No. EY-76-C-04-3683, July 1978.

4. Pefley, R. K., et al., Alcohol Fueled Vehicles Performance and Emissions, University of Santa Clara, paper prepared for Carnegie-Mellon Institute of Research, August 1981.

5. Brinkman, N. D., et al., "Exhaust Emissions, Fuel Economy, and Driveability of Vehicles Fueled with Alcohol Gasoline Blends," SAE Paper 750120, February 1975.

6. Menrad, H., "A Motor Vehicle Powerplant for Ethanol and Methanol Operation," Paper II-26, presented at the Third International Symposium on Alcohol Fuels Technology, May 29-31, 1979.

7. Allsup, J. R., Experimental Results Using Methanol/Gasoline Blends as Automotive Engine Fuel, Bartlesville Energy Research Center Report, RI-76-15, January 1977.

8. Broyles, A. R., "METHANOL, METHANOL, METHANOL," Chemical Week, Coal Week, and Coal Week International, New York, Dec. 1-2, 1981.

9. Floris, T., and M. Scarpetti, "METHANOL, METHANOL, METHANOL," sponsored by Chemical Week, Coal Week, and Coal Week International, New York, Dec. 1-2, 1981.

10. California Energy Commission, "Senate Bill 620: Alcohol Fleet Test Program," Staff Report CEC 920-6811, December 1981.

11. Hull, R. M., An Overview of Octane Booster Markets, Alcohol as an Octane Enhancer in the 80's Conference, San Antonio, Texas, March 24, 1982.

12. Abshire, A. D., Ethanol, Methanol and the Higher Alcohols, Alcohol as an Octane Enhancer in the 80's Conference, San Antonio, Texas, March 24-25, 1982.

13. From Oil and Gas Journal as summarized in Petroleum Supply Alternatives for the Northern Tier and Inland States, Through Year 2000. DOE-RA-0042-2, Vol. II, Oct. 31, 1979.

14. Chase, J. D., and B. B. Galvez, "Maximize Blend Ethers with MTBE and TAME," Hydrocarbon Processing, March 1981.

15. Energy Information Administration, 1981 Annual Report to Congress, (Tele-con information on not-yet-released Regional Appendix).

16. Atlantic Richfield Company, Atlantic Richfield Company Clean Air Act Sction 211(f) Waiver Application, Los Angeles, Calif., April 17, 1981.

17. Environmental Protection Agency, Grant of Application for a Fuel Waiver Submitted by the Atlantic Richfield Company (ARCO)--Decision of the Administrator.

18. Kuh, W. D., The Outlook for Methanol Blends for Use in Gasoline, San Antonio, Texas, March 24-25, 1982.

19. Booz, Allen & Hamilton Inc., Projected Heavy Crude Refining in California and Options for Disposal of Residual Oil Surplus, California Energy Commission, June 1981.

20. Bonner & Moore Associates, Inc., The 1985 California Oil Scenario Study, performed for an ad hoc group of California industry and government representatives, 20 March 1980.

21. Freeman, J. H., Alcohols - A Technical Assessment of Their Application as Fuels, API Publication No. 4261, July 1976.

22. Ingamells, J. C. and Lindquist, R. H. "Methanol as a Motor Fuel or a Gasoline Blending Component," SAE 750123, published in Alcohols as Motor Fuels, 1980.

23. Menrad, H., "A Motor Vehicle Powerplant for Ethanol and Methanol Operation," Paper II-26 presented at the Third International Symposium on Alcohol Fuels Technology, May 29-31, 1979.

24. Brinkman, N. D., "Vehicle Evaluation of Neat Methanol - Compromises Among Exhaust Emissions, Fuel Economy, and Driveability," Energy Research, Vol. III, 243-274 (1979).

25. Pefley, R. K. et al., Alcohol Fueled Vehicles Performance and Emissions, University of Santa Clara, paper prepared for Carnegie-Mellon Institute of Research, August 1981.

26. Choma, M. A., P. H. Havstad, MSME, A. O. Simki, MSME, and W. F. Stockhausen, MSME, Fuel Tolerance Tests with the Ford Proco Engine.

27. Bechtold, R. L., "Performance, Emissions, and Fuel Consumption of the White L-163-S Stratified-Charge Engine Using Various Fuels," Society of Automotive Engineers (Passenger Car Meeting) Troy Hilton, Troy Mich., June 5-9, 1978.

28. Lewis, J. M., W. T. Tierney, "Stratified Charge Engine Development with Broad Fuel Tolerance," paper presented at First International Automotive Fuel Economy Research Conference, Alexandria, Virginia, October 31 - November 1, 1979.

29. Evers, L. W., R. D. Fleming, and R. W. Hurn, "Efficiency and Emissions of a Stratified Charge Engine Optimization for Various Fuels," Society of Automotive Engineers, February 27 - March 3, 1978.

30. Norris-Jones, S. E. and J. T. Russell, "'FM' - A High Efficiency Combustion System for the Future Light-Duty Engine,?" The Engineering Resource for Advance Mobility, June 7-10, 1982.

31. Finegold, J. G., M. E. Karpuk, J. T. McKinnon, and R. Pasamaneck, Demonstration of Dissociated Methanol as an Automotive Fuel: System Performance, presented at the AS/ISES 1981 Annual Conference, Philadelphia, Penn., May 27, 1981.

32. Purohit, Ghanshyam and J. Houseman, "Methanol Decomposition Bottoming Cycle for IC Engines," SAE Paper 790427.

33. Finegold, J., "Panel on Hydrogen Automotive Engine Performance, Fuel Economy and Emissions Potential," World Hydrogen Energy Conference IV, June 16, 1982," IOM, SERI, June 23, 1982.

34. Baker, R. E., and E. E. Daby, "Engine Mapping Methodology," SAE Paper 770077, presented at International Automotive Engineering Congress and Exposition, Detroit, Mich., February 28-March 4, 1977.

35. Hirota, Toshio, Study of the Methanol-Reformed Gas Engine.

36. Inagaki, Tokuichi, T. Hirota and Z. Ueno, Combustion and Emission of Gaseous Fuel From Reformed Methanol in Automotive Engine.

37. Transportation Energy Group, Oak Ridge National Laboratory, Motor Vehicle MPG and Market Shares, March 1982.

38. Dowdy, Mack W., Comparisons and Future Potential in Conventional Engine Technology, Volume III, Jet Propulsion Laboratory, May 21, 1981 (soon to be released).

39. Heywood, John B., "Automotive Engines and Fuels: A Review of Future Options," Prog. Energy Combust. Sci., Vol. VII, pp. 155-184, Pergamon Press Ltd., Great Britain.

40. U. S. Department of Energy, Assessment of Methane-Related Fuels for Automotive Fleet Vehicles, February 1982.

41. OTA, Increased Automobile Fuel Efficiency and Synthetic Fuels, September 1982.

42. Pefley, R. K., Characterization and Research Investigation of Alcohol Fuels in Automobile Engines, Report No. ME-80-1, University of Santa Clara, December 1980.

43. Chigier N. (Ed), Energy and Combustion Science, Student Edition 1, Pergamon Press, London, 1979.

44. Hilden, D. L. and Parks, F. B., "A Single-Cylinder Study of Methanol Fuel - Emphasis on Organic Emissions," SAE Paper No. 760378, 1976.

45. Pischinger, F. F. and Kramer, K., "The Influence of Engine Parameters on the Aldehyde Emissions of a Methanol-Operated Four-Stroke Otto Cycle Engine," Section II-25, Proceedings of the Third International Symposium on Alcohol Fuels Technology, Asilomar, California, 1979.

46. Kamaga, B. S., Krishnan, K. V., Murphy, B. S. Pefley, R. K. Bechtold, R. L., and Edwards, G. W., "Evaluation of Methanol for Reduced Exhaust Emissions in a Single-Cylinder Research Engine," Section II-24, Proceedings of the Third International Symposium on Alcohol Fuels Technology, Asilomar, California, 1979.

47. Browning, L. H. and Pefley, R. K., Computer-Predicted Compression Ratio Effects on NOx Emissions from a Methanol-Fueled Engine, Dept. of Mechanical Engineering, University of Santa Clara, California, 1978.

48. Ecklund, E. E. and Pefley, R. K., Characterization and Research Investigation of Alcohol Fuels in Automobile Engines, Final Report, DOE Contract No. DE-AC03-78CS, 1980.

49. Brinkman, N. B., "Effect of Compression Ratio on Exhaust Emissions and Performance of a Methanol-Fueled Single-Cylinder Engine," SAE Paper No. 770791, 1977.

50. Brinkman, N. B., Gallopoulos, N. E. and Jackson, M. W., "Exhaust Emissions, Fuel Economy and Driveability of Vehicles Fueled with Alcohol-Gasoline Blends," SAE Paper No. 750120, 1975.

51. Choma, M. A., Havstad, P. V., Simko, A. O., and Stockhausen, W. F., "Fuel Tolerance Tests With the Ford PROCO Engine," SAE Technical Paper No. 810439, 1981.

52. Atlantic Richfield Company, Application to Environmental Protection Agency for Waiver for Oxygenated Fuels under the Clean Air Act, Section 206, 1981.

53. Acurex Corporation, "Clean Coal Fuels: Alternate Fuel Strategies for Stationary and Mobile Engines," Vol. VII: An Assessment of Methanol- Fueled Heavy-Duty Engines.

54. Neitz, A., and F. Chmela, Results of M.A.N.-FM Diesel Engines Operating on Straight Alcohol Fuels.

55. Komiyama, K., and I. Hashimoto, Spark-Assisted Diesel for Multifuel Capability, SAE technical paper series, International Congress and Exposition, February 23-27, 1981.

56. Bandel, W., and L. M. Ventura, "Problems in Adapting Ethanol Fuels to the Requirements of Diesel Engines," Paper No. B. 52, Session B. VII, IV International Symposium on Alcohol Fuels Technology, Oct. 5-8, 1980.

57. Preliminary Report, Project No. 611/01/2, Aukland, New Zealand.

58. Liquid Fuels Trust Board, Trial Programme on Methanol Diesel Buses, Project No. 3302/2, Aukland, New Zealand.

59. First Experiences with Alcohol-Gas Powered Methanol City Buses Used in Regular Service in Auckland and Berlin, Aukland, New Zealand.

60. Liquid Fuels Trust Board, Spirit of Transport, The Auckland Methanol Bus Experiment, Aukland, New Zealand.

61. Lewis, J. M., and W. T. Tierney, United Parcel Service Applies Texaco Stratified Charge Engine Technology to Power Parcel Delivery Vans, Progress Report, Truck Meeting, King-of-Prussia, Penn., Nov. 10-13, 1980.

62. Eng, K. D., and W. T. Tierney, Facing the Future With an Engine and its Fuel Considered as a System, presentation to the Sixth Annual Meeting - District 6, The Canadian Institute of Mining and Metallurgy, Victoria, B.C., Oct. 29-31, 1981.

63. "UPS Engine Ready for Real-Life Test," Diesel Equipment Superintendent, February 1982.

64. "The Engines of the Future, Transition 1: The Multi-Fuel Engine," Fleet Owner 1/80, McGraw-Hill Publication.

65. "The World of the 'World Truck'," Fleet Owner 7/80, McGraw-Hill Publication.

66. Lewis, J. M., and W. T. Tierney, Stratified Charge Engine Development with Broad Fuel Tolerance, presentation to SAE/DOT Symposium, Fort Wayne, Ind., Nov. 8-9, 1979.

67. Wagner, Joseph R., Fleet Operator Data Book, Vol. 1: National Data, BNL 50904, Brookhaven National Laboratory, September 1979.

68. Wagner, Joseph R., Fleet Operator Data Book, Vol. 2: Regional Data, Draft, Brookhaven National Laboratory, July 1949.

69. Wagner, Joseph and Naughton, Joanne, Fleet Operator Study: Geographic Aspects, July 1978, Informal Report 24708, Brookhaven National Laboratory.

70. Patterson, Phillip, Initial Finding of BNL's Fleet Operators Study, DOE letter to interested parties, April 27, 1978.

71. Patterson, Phillip, Additional Sensitivity Runs of the BNL Fleet Operator's Applicability Model, DOE letter to interested parties, May 4, 1978.

72. Average Yearly Mileage Figures for Fleet Automobile Vehicles, Letter from W. Brooks and D. Naughton of BNL to Phillip Patterson of DOE, October 20, 1977.

73. Wagner, J. R., Naughton, J., Brooks, W.P., Light Duty Highway Fleets, Interim Briefing for Department of Energy, March 3, 1948.

74. Wagner, J. R. and Davis, R. S., Fleet Operator Study, Interim Briefing, presented at DOE/TEC CCM at ANL on September 14, 1978.

75. Wagner, J. R., Interim Briefing, Projects in Progress, July 28, 1979.

76. Kulp, G., Shonka, D. B., Holcombs, M. C., Transportation Energy Conservation Data Book: Edition 5, Report 5765, Oak Ridge National Laboratory, November 1981.

77. MVMA Motor Vehicle Facts and Figures, 1979, Prepared by Motor Vehicle Manufacturers Association, Detroit, Michigan.

CHAPTER NINE

METHANOL UTILIZATION IN STATIONARY APPLICATIONS

A. INTRODUCTION

California electric utilities have been identified as a likely market for methanol because of their current dependence on oil, the apparent ease of adaptation of boilers and combustion turbines for methanol use, the need to reduce emissions of air pollutants, and the ability to consume large quantities with a minimum of infrastructure development. Industrial energy applications have also been considered as potentially significant. This chapter describes an investigation of the potential use of methanol in the California utility and industrial sectors. The investigation surveyed current and projected energy demand and supply (Section B), the technologies available for methanol utilization (Section C), and the factors influencing utility and industrial fuel selection (Section D) in order to identify and quantify potential methanol roles (Section E). Barriers to widespread use of methanol in stationary applications are summarized in Section F along with the implications of policy options that could be used to overcome these barriers. Conclusions are presented in Section G.

The analysis presented below is based on discussions with representatives of key utilities and regulatory agencies as well as reviews of utility, industrial, and CEC supply/demand forecasts and technical literature on methanol applications.

B. CALIFORNIA STATIONARY ENERGY DEMAND AND SUPPLY

This section establishes potential markets for methanol in the stationary sector with emphasis on the next twenty years. The markets include utility and industrial fuel use and industrial cogeneration.

1. Overview of Utility Demand and Supply Projections

Table 9-1 shows current and projected California utility energy demand and peak capacity requirements. It should be noted that these are projections by the utilities and that the California Energy Commission (CEC) projects growth rates roughly half of those in Table 9-1. The analysis concentrated on Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and the Los Angeles Department of Water and Power (LADWP), since they represent 87 percent of the total demand and a similar proportion of the oil and gas usage. A summary of generation technologies in the resource plans submitted by the three utilities to the CEC is presented in Table 9-2.

Practically all of the gas and residual oil shown in Table 9-2 is burned in conventional steam turbine units, while the distillate oil (and a small proportion of the gas) is used in peaking combustion turbines and (in SCE's case) in combined cycle units. In 1981, SCE's steam turbine generation was split 38:62 between oil and gas, while PG&E used oil in their steam turbine units only 20 percent of the time.

Table 9-1. UTILITY ADOPTED STATEWIDE DEMAND FORECASTS

	PEAK (GW)				AVERAGE ANNUAL GROWTH RATE (%)		
	1981	1987	1994	2000	1981-87	1981-94	1981-2002
PG&E	16	16	18	22	0.6	0.9	1.5
SCE	14	14	17	20	0.8	1.6	1.7
LADWP	5	5	5	6	-2.6	-0.3	0.4
San Diego Gas & Electric	2	2	3	3	2.1	2.3	2.3
Calif. Dept. of Water Resources	1	2	2	2	0.8	1.0	1.1
Other	1	1	2	2	1.0	1.0	1.3
TOTAL	39	40	47	55	0.4	1.5	1.7
	ENERGY REQUIREMENTS (10^3 GWh)				AVG. ANNUAL GROWTH RATE (%)		
	1981	1987	1994	2000	1981-87	1981-94	1981-2002
PG&E	80	84	95	120	0.9	1.4	2.0
SCE	70	75	88	100	1.3	1.8	1.7
LADWP	23	22	25	28	-0.7	0.7	1.0
SDG&E	12	13	15	18	1.7	2.1	2.1
DWR	8	12	13	13	8.0	4.0	2.6
Other	6	6	7	8	1.2	1.6	1.8
TOTAL	199	212	243	287	1.1	1.6	1.8

SOURCE: "Integrated Supply and Demand," CEC Report #P300-82-007, July 1982.

Table 9-2. UTILITY RESOURCE PLANS

	10^3 GWh PRODUCED					
	GAS OR RESIDUAL OIL	DISTILLATE OIL	COAL	NUCLEAR	OTHER*	TOTAL
PG&E						
1981	33	0.3	0	3	44	80
1990	19	0	0	18	52	89
2000	20	0.3	0	18	75	113
SCE						
1981	34	4	10	1	20	69
1990	19	3	11	16	31	80
2000	15	3	18	20	40	96
LADWP						
1980	10	small	6	0	5	21
1990	5	small	10	2	5	22
2000	5	small	11	2	8	27

*Hydro (average conditions), renewables, cogeneration, purchases.

A key uncertainty in the growth of utility markets for methanol is the predicted decline in utilization of oil- and gas-fired steam turbine units. Two forces are at work here: (1) retirement of older, low-efficiency units under the combined pressures of rising maintenance and fuel costs, and reduction of capacity factors for newer units as the new out of basin coal and nuclear plants come on line, and (2) the pressure to reduce emissions in metropolitan areas increases. The latter factor is particularly significant for SCE which has about 8,000 MW of modern steam turbine units located in environmentally sensitive areas of southern California. Availability of a competitive, environmentally acceptable fuel, coupled with the combination of a financial climate prohibitive to capital investment, could lead to substantially increased reliance on existing steam turbine units relative to that shown in Table 9-2. Methanol could satisfy these fuel specifications, but so could natural gas, if it is available.

As a consequence of its gas supplying role, PG&E has long-term gas procurement arrangements which they believe will satisfy a large proportion of their fuel needs (in addition to the needs of their gas customers) for at least the next ten years, and this takes them beyond the life expectancy of many of their steam turbine units. On the other hand, SCE and LADWP are subject to curtailment in the event of gas shortages, and thus cannot rely on gas being available to them. They are also concerned about the price increases that will follow deregulation, and are thus very interested in finding alternative fuels for their existing boilers.

Peaking turbines and combined cycle units, which must use expensive distillate fuels when gas is not available, are likely targets for methanol, but the projected fuel use in such units is small compared to steam turbines. There is, however, a chance that some additional combined cycle units will be built for intermediate load duty, and the likelihood of this could be increased if availability of competitively priced methanol was assured.

2. Existing Utility Units

Existing steam turbine and combined cycle units appear to represent the largest potential utility market for methanol, certainly in the next decade, and probably in the 1990's as well. (Except as a very small first step in the early phase of methanol supply build-up, existing combustion turbines represent negligible fuel use--a few hundred gigawatt hours in 1979.) Table 9-3 identifies the steam turbine and combined cycle generating capacity for the three major utilities. The steam turbines are split between modern high efficiency units (heat rate less than 10,000 Btu/kWh, generally on-line after 1960) and older units. SCE's combined cycle units all have substantial useful life remaining. Projected utilization of these units, shown in Table 9-2, indicates reduced reliance on them. (Most of the residual oil and gas in Table 9-2 is targeted for the modern steam turbine units, while nearly all of the distillate oil is for the combined cycle units.) However, as discussed above, methanol availability could increase reliance on these units. Operating all of the modern steam turbine and combined cycle units at a 50 percent capacity factor equates to more than 80,000 tons of methanol per day.

SCE represents the most significant potential market for methanol because of their current dependence on oil and gas, the relative modernity of their generating units, and the location of most of their units in environmentally sensitive areas. PG&E, while also using large quantities of oil and gas today, is a less likely target for methanol because of their access to natural gas and the relative age of their steam turbine units. Facing high oil prices and a shortage of natural gas, PG&E would look first toward a source of synthetic natural gas that could be integrated with their gas supply operations. LADWP's situation is similar to SCE's in regard to oil and gas dependence and environmental pressures, but they have made major commitments

Table 9-3. Existing Oil- and Gas-Fired Generating Capacity

	CAPACITY (GIGAWATTS)			
	MODERN STEAM TURBINES	OLDER STEAM TURBINES	COMBINED CYCLE	TOTAL
SCE	8.0	0.9	1.0	9.9
PG&E	4.4	2.9		7.3
LADWP	2.2	0.9		3.1

toward a shift to out of state coal-fired generation and apparently have less difficulty in financing such ventures.

3. SCE and LAWDP Systems

Oil and gas fired elements of the SCE and LADWP systems have been studied in detail because of their potential significance in the transition to large-scale methanol use. Key parameters of the two sets of existing units are listed in Tables 9-4 and 9-5. Unless otherwise noted, all steam turbine units can currently fire either residual oil or natural gas, while all combined cycle and combustion turbine units can fire distillate oil or natural gas. The SCE oil distribution network, which could play a role in delivery of methanol, is illustrated in Figure 9-1.

New baseload facilities in the SCE and LADWP resource plans are either nuclear or coal-fired, but SCE's resource plan calls for additions of 540 MW of new combustion turbines in the 1992-95 time period (to augment peaking capacity) which could fire liquid or gaseous fuels. Expected capacity factors for these units are less than 5 percent.

4. Industrial Energy Demand and Supply

Stationary industrial energy use in California for the year 1979 was approximately 0.9×10^{15} Btu, with about two-thirds derived from natural gas and the remainder split about evenly between oil and electricity. An increase to 1.1×10^{15} Btu is expected by the year 2000 (Ref. 1).

Table 9-6 shows a breakdown of energy used in 1974 for the top eleven industries by SIC code. Energy intensiveness of each group is also shown since those that are energy intensive will be more sensitive to fuel cost than those that are not.

Additional detail on the top energy users is provided in Table 9-7. All of the boiler applications and a portion of the furnace and kiln applications are potential users of methanol. Many boiler operators are very flexible, relative to fuel switching and are very sensitive to fuel prices. Long-term fuel supply contracts are rare in the industrial sector.

The biggest group of industrial energy users are the petroleum refineries who derive much of their energy from burning low value products within the refinery (e.g., for Chevron's California refineries the ratio is 2/3 internal fuels to 1/3 purchased natural gas). However, many of the refineries are in environmentally sensitive areas and are under pressure to reduce emissions. They also have a need for offsets whenever expansion is planned. Thus, they should not be ruled out as potential methanol users (although Table 9-6 indicates they will be particularly sensitive to fuel cost).

Optimistic estimates of the potential market for methanol in the industrial sector can be obtained by including all of the boilers and half of the kilns, furnaces, and petroleum refining applications indicated in Tables 9-6 and 9-7. The resulting estimates are 0.5×10^{15}Btu/yr (70,000 tons/day of

Table 9-4. SCE OIL AND GAS FIRING UNITS

NAME AND UNIT NO.	DATE INSTALLED	CAPACITY (MW)	HEAT RATE FOR OIL FIRING (Btu/kWh)	PREDICTED CAPACITY FACTOR (%)				METHOD OF SUPPLY			AIR BASIN
				1987	1992	1997	2000	WATER	PIPELINE	RAIL	
STEAM TURBINE UNITS											
Long Beach #10	1928	106	12,615	R	R	R	R	X	X	X	SC
Long Beach #11	1930	50	"	R	R	R	R	X	X	X	SC
Redondo #1	1948	74	12,927	R	R	R	R		X	X	SC
Redondo #2	1948	74	"	R	R	R	R		X	X	SC
Redondo #3	1948	70	13,319	R	R	R	R		X	X	SC
Redondo #4	1949	74	12,927	R	R	R	R		X	X	SC
Redondo #5	1954	175	9,988	6	R	R	R		X	X	SC
Redondo #6	1957	175	"	6	R	R	R		X	X	SC
Redondo #7	1967	480	9,045	52	47	49	47		X	X	SC
Redondo #8	1967	480	"	52	47	49	47		X	X	SC
High Grove #1	1952	32.5	11,564	R	R	R	R			X	SC
High Grove #2	1952	32.5	"	R	R	R	R			X	SC
High Grove #3	1953	44.5	10,822	R	R	R	R			X	SC
High Grove #4	1955	44.5	"	R	R	R	R			X	SC
Etiwanda #1	1953	132	10,337	R	R	R	R		X	X	SC
Etiwanda #2	1953	132	"	R	R	R	R		X	X	SC
Etiwanda #3	1963	320	9,619	49	36	37	38		X	X	SC
Etiwanda #4	1963	320	"	49	36	37	38		X	X	SC
El Segundo #1	1955	175	9,988	6	18	25	24		X		SC
El Segundo #2	1956	175	"	6	18	25	24		X		SC
El Segundo #3	1964	335	9,367	49	36	37	38		X		SC
El Segundo #4	1965	335	"	49	36	37	38		X		SC
Alamitos #1	1956	175	9,988	6	18	25	24		X		SC
Alamitos #2	1957	175	"	6	18	25	24		X		SC
Alamitos #3	1961	320	9,503	49	36	37	38		X		SC
Alamitos #4	1962	320	"	49	36	37	38		X		SC
Alamitos #5	1966	480	8,995	52	47	49	47		X		SC
Alamitos #6	1966	480	"	52	47	49	47		X		SC
San Bernardino #1	1957	63	9,730	R	R	R	R			X	SC
San Bernardino #2	1958	63	"	R	R	R	R			X	SC
Huntington Beach #1	1958	215	9,147	21	35	35	35	*	X		SC
Huntington Beach #2	1958	215	9,202	21	35	35	35	*	X		SC
Huntington Beach #3	1961	215	9,185	21	35	35	35	*	X		SC
Huntington Beach #4	1961	225	9,176	21	35	35	35	*	X		SC
Mandalay #1	1959	215	8,997	21	35	35	35	X			SCC
Mandalay #2	1959	215	"	21	35	35	35	X			SCC

*Huntington Beach units are connected to a Gulf Oil Co. marine terminal but it is currently used 100% of the time by Gulf.

Table 9-4. SCE OIL AND GAS FIRING UNITS (continued)

NAME AND UNIT NO.	DATE INSTALLED	CAPACITY (MW)	HEAT RATE FOR OIL FIRING (Btu/kWh)	PREDICTED CAPACITY FACTOR (%)				METHOD OF SUPPLY			AIR BASIN
				1987	1992	1997	2000	WATER	PIPELINE	RAIL	
STEAM TURBINE UNITS											
Coolwater #1	1961	65	9,596	12	23	59	53			X	SDT
Coolwater #2	1964	81	"	12	23	59	53			X	SDT
Ormond Beach #1*	1971	750	9,066	49	44	43	45	X			SCC
Ormond Beach #2*	1973	750	"	49	44	43	45	X			SCC
COMBINED CYCLE UNITS											
Long Beach #8**	1976	303	9,980	34	34	34	34	X	X		SC
Long Beach #9**	1977	227	9,980	34	34	34	34	X	X		SC
Coolwater #3	1978	241	8,657	45	45	45	45			X	SDT
Coolwater #4	1978	241	8,657	45	45	45	45			X	SDT
LARGE COMBUSTION TURBINES											
Etiwanda #5	1969	118	14,470	1	2	3	3		X		SC
Alamitos #7	1969	130	14,470	1	2	3	3		X		SC
Huntington Beach #5	1969	130	14,470	1	2	3	3		X		SC
Mandalay #3	1970	125	14,470	1	2	3	3	X			SCC
Elwood #1	1974	53	12,100	1	2	3	3				SCC

AIR BASINS:

R = contingent retirements

SC - South Coast (Los Angeles and vicinity)
SCC - South Central Coast (coastal Ventura and Santa Barbara Counties)
SDT - Southeast Desert

NOTES: *Environmental restriction on firing rate.
**Environmental restriction on capacity factor.

Table 9-5. LADWP OIL AND GAS-FIRED UNITS

NAME AND UNIT NO.	DATE INSTALLED	CAPACITY (MW)	HEAT RATE FOR OIL FIRING (Btu/kWh)	PREDICTED CAPACITY FACTORS				METHOD OF SUPPLY			AIR BASIN
				1987	1992	1997	2000	WATER	PIPELINE	RAIL	
STEAM TURBINES											
Harbor #1	1943	72		0	R			X			SC
2	1947	67		0	R			X			
3	1949	86		1	R			X			
4	1948	86		1	R			X			
5	1949	86		1	R			X			
Valley #1	1954	94		2	0	R					
2	1954	101		3	0	R					
3	1955	164		11	0	R					
4	1956	160		16	0	R					
Scattergood #1	1958	179	10,070	29	5	2	2				
2	1959	179	9,980	41	5	3	3				
3	1974	496(284)*	9,980	61	81	81	81				
Haynes #1	1962	222	9,810	66	27	4	10	X			
2	1963	232	9,980	54	17	3	4	X			
3	1964	220	9,820	63	12	3	6	X			
4	1965	227	9,780	61	2	0	5	X			
5	1966	341	10,320	71	39	30	25	X			
6	1967	341	8,630	72	25	14	14	X			SC
COMBUSTION TURBINES											
Harbor #6	1972	19		0	0	0	0	X			SC
7	1972	19		0	0	0	0	X			
8	1972	19		0	0	0	0	X			
9	1972	19		0	0	0	0	X			SC

*Built to fire oil or gas at 496MW, environmentally restricted to gas at 284MW.

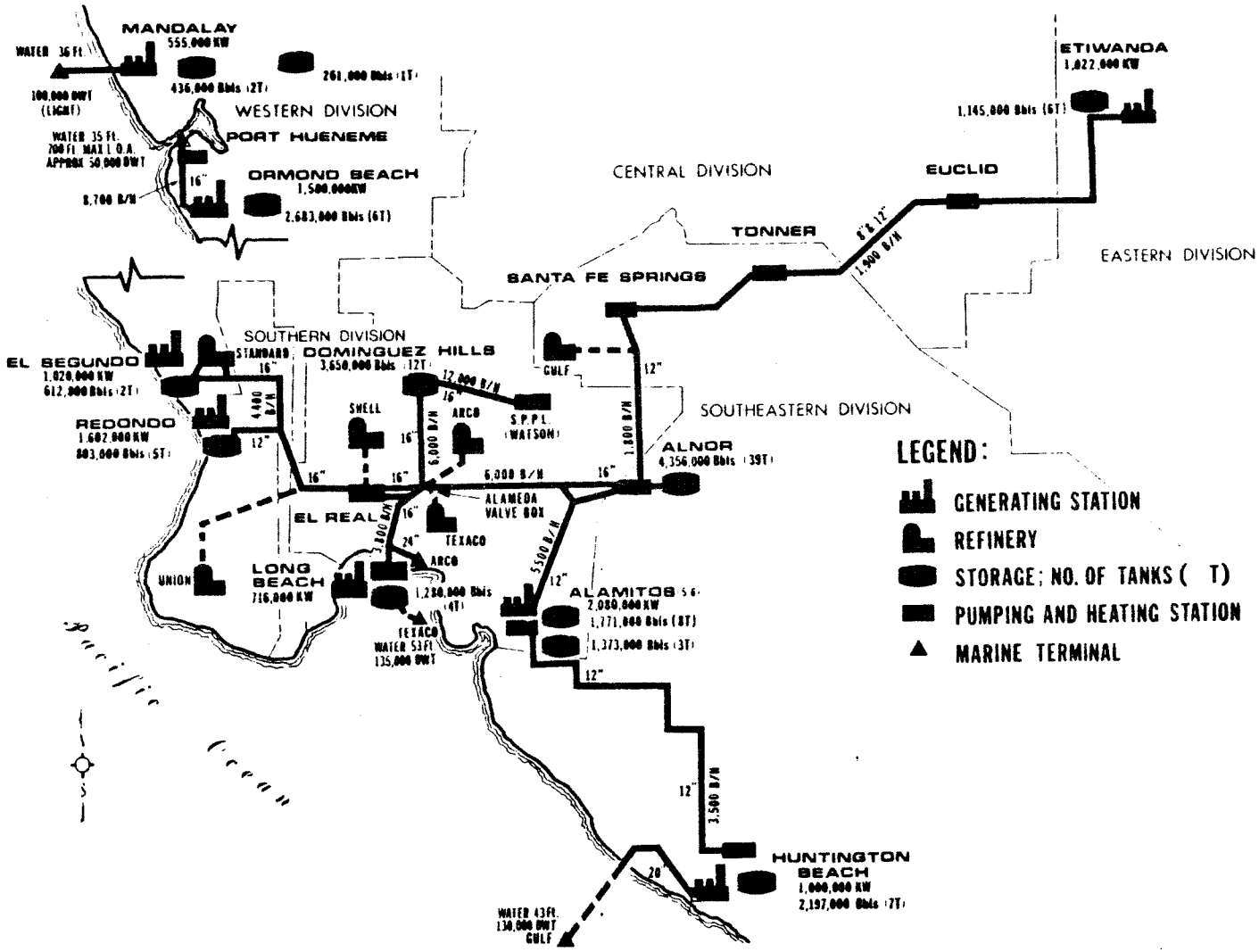


Figure 9-1. SOUTHERN CALIFORNIA EDISON COMPANY FUEL OIL PIPELINE SYSTEM STORAGE AND DELIVERY FACILITIES (Source: SCE)

Table 9-6. TOP ENERGY CONSUMING INDUSTRIES IN CALIFORNIA, 1974 (Ref. 2)

SIC CODE	CLASSIFICATION	TOTAL ENERGY USE (10^{12} Btu)	ENERGY INTENSIVENESS (10^3 Btu/$ of product)
29	Petroleum and coal	165	49
32	Stone, clay, and glass	100	53
20	Food and kindred	92	8
10-14	Mineral extraction	92	NA
33	Primary metals	60	27
28	Chemicals	57	17
26	Paper and allied products	36	21
34	Fabricated metals	31	7
37	Transportation equipment	28	2
24	Lumber and wood	22	8
36	Electrical machinery	17	3
	Other	54	
		Total 755	

methanol) at present and 0.6 x 10^{15}Btu/yr (84,000 tons/day) in the year 2000. The most likely users would be the small fraction of this market (on the order of 10%) that currently have no access to natural gas and must rely on expensive distillate oil.

The need for offsets may provide an inducement to use methanol in a number of industrial applications. The value of methanol in producing offsets is discussed in Section D below.

5. Industrial Cogeneration

A recent study performed for the California Energy Commission (Ref. 27) provides estimates of the potential for methanol use in industrial cogeneration systems based on gas turbines. The fuel use estimates for electrical generation are repeated in the following table (fuel use for industrial purposes by the cogenerators is part of the total accounted for in subsection 4).

PERIOD	NEW GENERATING CAPACITY (MW)	GAS TURBINE FUEL USE AT END OF PERIOD (tons/day of Methanol)
1979 - 1985	587	3,300
1986 - 1992	935	8,600
1993 - 2000	765	12,900

These estimates are for the "current trends" case in Ref. 27. Substantially, higher estimates are also provided in a "preferred outlook" case. As in subsection 4, methanol would have to compete with distillate oil and natural gas (if available) for this market.

Table 9-7. FUEL CONSUMING PROCESSES IN KEY INDUSTRIES (Ref. 3)

SIC	INDUSTRY	PURCHASED FUEL (10^{12} Btu)	FUEL CONSUMING PROCESSES
20	Food	112.5	
2011	Meatpacking	5.45	boilers
2026	Milk	4.53	boilers
2033	Fr. & Veg. Canning	19.32	boilers
2034	Dried Fr. & Veg.	5.99	food dryers
2037	Frozen Fr. & Veg.	2.345	food freezers
2038	Frozen Specialities	1.997	food freezers
2047	Pet Food	1.34	boilers
2048	Animal Feeds	3.26	boilers(60%),grain dryers(40%)
2051	Bakeries	5.05	boilers
2063	Sugar Refineries	25.60	boilers
2082	Beer	3.22	various
2084	Wine & Brandy	3.34	boilers
2065	Distilled Liquor	2.05	boilers
2086	Soft Drinks	2.51	CO_2 generators
2091	Seafood Canning	3.11	boilers
26	Paper	33.89	
261	Pulp Mills	1.06	boilers
262	Paper Mills	12.07	boilers
263	Paperboard Mills	17.34	boilers
265	Containers & Boxes	6.01	boilers
28	Chemicals	77.91	
2813	Industrial Gases	8.43	various(main energy is elec.)
2821	Plastics	8.35	boilers
2822	Synthetic Rubber	0.60	boilers
2841	Soap & Detergents	3.46	boilers(30%), various(?%)
2844	Toilet Goods	0.71	boilers(30%), various(?%)
2851	Paint	2.73	grinders, mixers
2865	Organic Chemicals	1.19	boilers
2869	Organic Chemicals	27.87	boilers
2873	Nitrogen Fertilizer	19.36	boilers(50%), various (50%)
29	Petroleum & Coal	173.83	
2911	Oil Refineries	198.6	boilers(25%), tubestills & Others (75%)
32	Stone, Clay, Glass	126.41	
321	Flat Glass	3.68	melters(70%), annealers(10%)
322	Other Glass	18.24	melters(70%), annealers(10%)
3241	Cement	41.29	cement kiln
325	Brick & Tile	9.20	brick kiln
326	Pottery	3.91	clay kilns
3276	Lime	3.93	lime kilns
33	Metals	69.00	
3312	Iron & Steel Mfg.	11.22	coke oven, blast furnace, steel furnace, soak pit
3315	Stell Wire	0.76	heat and reheat furnace
3316	Cold Finish Steel	0.54	heat and reheat furnace
3317	Nonferrous Wire	1.61	heat and reheat furnace
332	Steel Casting	5.93	reverberatory furnaces
3341	Nonferrous Scrap	3.46	reverberatory furnaces
335	Nonferrous Rolling	6.96	heat and reheat furnaces
336	Nonferrous Casting	4.48	reverberatory furnaces
339	Metal Heat Treat	11.64	heat and reheat furnaces
Total of California Mfgs.		753.53	

C. METHANOL UTILIZATION TECHNOLOGIES FOR STATIONARY APPLICATIONS

For stationary applications, methanol is primarily considered as a potential fuel for turbines, boilers, or fuel cells used in utility or industrial power generation plants. Methanol use in gas turbines can be further divided between simple turbines for peak and intermediate load requirements and combined cycle configurations for base load requirements. Repowering a steam cycle utility plant to a methanol based combined cycle configuration is considered as a base or intermediate load utilization.

Boiler use of methanol is considered here for steam generation to produce either process steam for industrial use or turbine steam for utility use. This section summarizes information compiled on performance, fuel requirements, emissions, safety, equipment conversion, equipment and operating costs, and maintenance for methanol use in turbines, boilers and fuel cells.

1. Utilization of Methanol in Gas Turbines

a. Performance. Key performance features of methanol as a fuel for gas turbines that will be considered are as follows:

(1) Efficiency (usually expressed as heat rate in fuel Btu/kW-hr based on the higher heating value of the fuel).

(2) Existing facility power rating substituting methanol as the fuel.

(3) Reliability of turbines using methanol.

(4) Availability of turbines using methanol.

Gas Turbine Heat Rate. Performance tests have been run by Southern California Edison (SCE) (Ref. 4), Florida Power Corp (Ref. 5), and General Electric Company (Ref. 6), with available results given in Table 9-8. The heat rate using United Technology Corporation's (UTC's) FT4C-1 free turbine in the SCE test is slightly better for methanol then for natural gas or Jet A fuel. Depending on the mode of operation, the methanol heat rate is about 1 to 3 percent less than that for Jet A or natural gas.

Further data for the SCE tests are presented in Table 9-9. With Jet Fuel A, it was necessary to inject water with the fuel to meet the local NO_x emission requirement whereas running methanol did not require water injection. Hence in comparing efficiencies, the wet Jet Fuel case should be compared with the dry methanol case. When running at a 24 MW load for both fuels, methanol shows a 2.4 percent lower heat rate; when running at an imposed turbine temperature limitation, methanol shows a 3.2 percent lower heat rate.

Gas Turbine Facility Power Rating. Referring to the SCE test data presented in Table 9-9, the power rating of the FT4C engine when running at an imposed free turbine inlet temperature limitation of 1206°F is

Table 9-8. METHANOL GAS TURBINE PERFORMANCE TESTS

TEST FACILITY	GAS TURBINE	FUEL TESTED	HEAT RATE (LHV Btu/kW/hr	POWER OUTPUT (MW)	TEST DURATION (hrs)	COMMENTS
Southern California Edison Ellwood Energy Support Facility Goleta, CA 1978 - 1979	UTC's Twin-pac FT4C; CC4C-1 gas generator + FT4C-1 free turbine	MeOH (dry)	11,722	24	Total of 523 hrs testing with Methanol	Data from Ref. 4
		MeOH (dry)	11,481	27.1		
		MeOH (wet), 0.2:1	11,530	27.9		
		Jet A (dry)	11,863	24		
		Jet A (wet)	11,863	25.5		0.35 to 0.5 lb H_2O/ lb fuel
		Nat. Gas (dry)	11,863	24		
		Nat. Gas (dry)	11,863	25.0		
Florida Power Corp. Bayboro Station 1974	UTC's FT4C-1 DF gas turbine	MeOH	N/A	18	12	Power output of 18 MW limited due to fuel supply system; date from Ref. 5
General Electric Laboratory	Single combustor only from MS-7001B 65-MW rated size	MeOH	estimated 2% efficiency increase over that for No. 2 Dist. Fuel	estimates 6% gain over that for No. 2 Dist. Fuel.	N/A	statements taken from Ref. 6.

Table 9-9. SCE METHANOL GAS TURBINE PERFORMANCE TESTS[1]

	JET A		METHANOL	
WATER INJECTION (lb H_2O/lb fuel) (Note 1)	DRY	0.35 to 0.5	DRY	0.2
Running in all modes to dry base power load of 24 MW				
MW	24	24	24	24
Heat Rate (LHV-Btu/kW-hr)	11,863	12,014	11,722	11,863
T_2 (°F) (Note 2)	1,206	1,180	1,153	1,137
Fuel Consumption: gpm	37.4	38.0	82.4	83.4
Running in all modes to dry base load of T_2 = 1206°F				
T_2 (°F)	1,206	1,206	1,206	1,206
MW	24.0	25.5	27.1	27.9
Heat Rate (LHV-Btu/kW-hr)	11,863	11,863	11,481	11,530
Fuel Consumption: gpm	37.4	39.8	91.3	94.5

NOTES: (1) Water injected with Jet A to meet NO_x emission limitation; dry methanol did not require water for NO_x.

(2) T_2 in the free turbine inlet temperature.

25.5 MW for Jet A and 27.9 MW for methanol. This represents a power rating increase of methanol over Jet A of 9.4 percent while maintaining a 2.8 percent heat rate advantage. This compares well with estimates of 6 percent and 10 percent power output gains by GE and Westinghouse respectively when using methanol (refer to Table 9-8). In Florida Power Corporation's test using UTC's FT4C-1DF engine, the output was limited to 18 MW out of a maximum capacity of 34 MW burning oil. The power output was limited because the fuel supply system was not adjusted for the higher volumetric flows of methanol compared to a distillate fuel.

b. Fuel Requirements. Fuel requirements are defined here as the fuel specifications that must be met in order to effectively use methanol in gas turbines. There are currently no standard specifications for methanol as a gas turbine fuel. The ASTM Specifications for Gas Turbine Fuel Oils (D-2880) are applicable to hydrocarbon liquid fuels varying from naphtha (No. 0-GT grade) to residual (No. 4-GT) fuel oils. Pure methanol would meet all the specifications for the No. 0-GT fuel. However, since methanol's flash point of 52°F is below 100°F and its viscosity of 0.6 cSt at 40°C is less than

7.3 cSt, the ASTM recommendation is that the turbine manufacturer be consulted with respect to safe handling and fuel system design.

The gas turbine fuel oils' specifications also have a maximum water and sediment volume% of 0.05 for grades 0-GT, 1-GT, and 2-GT and 1.0 volume% for 3-GT and 4-GT. Since water and methanol are miscible with each other, volume% as a specification term is inappropriate. Methanol will always contain some water, the amount depending on the degree of water fractionation at the methanol production plant plus the amount of water picked up in transit from the production site to the gas turbine inlet. The degree of water fractionation at the methanol synthesis plant is a choice that must be made with the following considerations:

(1) Including limited amounts of water in methanol has the effect of increasing both the heat rate and power rating of the gas turbine unit. However, this is a minor effect since the amount of water in fuel grade methanol will probably range from 1 to 5 weight%. From the SCE test, the effect of adding 17 weight% water to methanol was to increase the heat rate by about 1 percent and the plant rating by about 3 percent.

(2) The incremental costs to produce the "dry," or chemical grade methanol vs. the "wet" or fuel grade methanol.

(3) The incremental costs to ship the wet methanol with the extra water vs. the dry methanol.

The water that is picked up by methanol in transit could be a particular concern to turbine operators if the water contains trace metals. For regular turbine fuel oils, ASTM recommends a maximum of 0.5 ppm by weight for vanadium, sodium + potassium, calcium, and lead to prevent turbine blade corrosion. In order to reduce the metals to the recommended 0.5 ppm level, fuel oils can be processed by separating water (which includes much of the metals) via gravity settling, coalescing, and filtration. With methanol, these methods are not applicable since water and methanol are miscible. Hence, any water picked up in trucks, pipelines, tankers, barges, etc. containing dissolved metals would carry through to the gas turbine. In addition, since methanol's heating value is about half that of fuel oils, the mass flow rate is double and the resulting trace metal requirement should be half that for fuel oils, or 0.25 ppm by weight (ppmw).

Other components typically found in methanol are not expected to be a concern. Three compounds found in methanol include dimethyl ether, methyl formate, ethanol (and others); however, the total hydrocarbon impurities amount to only about 2000 ppmw maximum using current methanol synthesis technology (Ref. 7).

c. Emissions. Emissions considered here from the use of methanol as a fuel include NO_x, CO, hydrocarbons, aldehydes, solid particulates and SO_2 in the exhaust gases and methanol from fuel vaporization losses.

NO_x Emissions. NO_x emissions measured during the SCE test program using UTC's FT4C-1 gas turbine are presented in Table 9-10 as a function of load. Methanol produces exhaust well below the NO_x limit at all loads, while both Jet A and natural gas without water injection produce exhaust above the limit at all load levels tested. In order to reduce the emissions below 75 ppmv, water must be injected with Jet A fuel at a 0.35 - 0.5 to 1 weight ratio and with natural gas at a 0.3 to 1 weight ratio. Water injection, however, has the disadvantage of increasing the heat rate as seen in Table 9-9. (It should be noted that local air pollution control agencies in California have tighter NO_x limits, but methanol can probably meet them without water injection.)

The primary reason for methanol's lower NO_x emissions is due to its lower adiabatic flame temperatures which are approximately 200°F and 300°F lower than natural gas and Jet A fuels, respectively. The turbine tests show that for all fuels, NO_x increases as the load increases. This is apparently due to the effect of increasing the relative fuel to air flow while the load increases as shown Table 9-11. As the fuel to air weight ratio increases, it is probable that the maximum combustor temperature increases also, thereby increasing the NO_x formed.

Earlier short-duration tests by the Florida Power Corp. using a UTC FT4C-1DF gas turbine also confirm the low NO_x emissions for methanol. Tests showed methanol well below the EPA limit of 75 ppmv, representing roughly a 74 percent NO_x reduction when compared to No. 2 fuel oil. GE laboratory tests also confirm the significantly lower (by about 60 percent) NO_x emissions when compared to No. 2 distillate fuel.

The effect of water injection in reducing NO_x emission from methanol was also investigated by SCE. The data in Table 9-12 indicate that a 50 to 60 percent reduction is possible when adding 0.22 lb. water per lb. methanol.

CO Emissions. CO emissions as measured during the SCE test program using UTC's FT4C-1 gas turbine are presented in Table 9-12. CO emissions are higher for methanol than for Jet A (dry) at all load levels. However, when water is injected with Jet A fuel, the CO emissions apparently are similar to those with methanol.

Table 9-10. NO_x EMISSION LEVELS IN SCE TEST

LOAD	PPM NO_x @ 15% O_2		
	8 MW	16 MW	25 MW
Methanol (dry)	20	35	40
Jet A (dry)	90	140	180
Jet A (wet)	--	45	70
Natural Gas (dry)	--	80	110
Natural Gas (wet)	--	50	70

Table 9-11. FUEL/AIR RATIOS AND NO_x EMISSIONS AS A FUNCTION OF LOAD

FUEL	MW OUTPUT	CALCULATED FUEL TO AIR WEIGHT RATIO	PPMV - NO_x @ 15% O_2
Methanol (dry)	10	.0184	25
	15	.0311	35
	20	.0342	40
	24	.0358	42
	25	.0372	45
Jet A (dry)	10	.0130	110
	15	.0144	140
	20	.0157	160
	24	.0167	180
	25	.0173	185

Table 9-12. EFFECT OF WATER INJECTION ON NO_x EMISSIONS FROM METHANOL

MW OUTPUT	PPMV NO_x @ 15% O_2	
	DRY METHANOL	WET METHANOL
6	22	11
17	35	20
25	45	18

Earlier tests by Florida Power Corp. also showed methanol having higher CO emissions than dry No. 2 Distillate Fuel Oil. At 20 MW load, CO emissions, corrected to 15 percent O_2, were about 60 ppmv compared to 30 ppmv for No. 2 Fuel Oil. When the load was decreased, CO emissions increased to that shown in Table 9-13.

Table 9-13. CO EMISSIONS IN SCE TEST

LOAD	PPM CO (as measured)		
	8 MW	16 MW	25 MW
Methanol (dry)	250	100	40
Jet A (dry)	225	50	10
Jet A (wet)	-	110	15

It should be noted here that while dry methanol has higher CO emissions than dry Jet A or No. 2 Fuel Oil, if NO_x emissions of either fuel oil are brought down via water injection to the level of NO_x emissions of methanol, then the CO emissions of methanol and the fuel oils will tend to be about equal. This effect is illustrated in Table 9-14. These values show that at the load levels of 20 and 25 MW, the combined emissions of CO and NO_x for both dry methanol and water-injected Jet A are about equal.

The SCE tests indicated CO emissions of natural gas were significantly higher than for methanol or Jet A fuel. At 25 MW load conditions, CO from dry natural gas was about 2-3 times that from dry methanol (125-175 ppmv vs. 60 ppmv). At lower loads, natural gas still had significantly higher emissions. It should be noted, however, that testing of smaller turbines with an air atomization nozzle produced 23 percent less CO emissions with gas than Jet A fuel. The turbine tested was a 60-HP Solar International T-45M-13 machine.

Hydrocarbon Emissions. During the SCE tests, hydrocarbon emissions from methanol were higher than from Jet A but about an order of magnitude less than emissions for natural gas. At a 24 MW load, Jet A

Table 9-14. COMPARISON OF EMISSIONS FROM WATER INJECTED JET A AND DRY METHANOL

LOAD LEVEL (MW)	JET A			DRY METHANOL	
	REQUIRED WATER INJECTION RATE (lb/lb fuel)	NO_x (ppmv @ 15% O_2)	CO (ppmv @ 15% O_2)	NO_x (ppmv @ 15% O_2)	CO (ppmv @ 15% O_2)
20	0.7	40	90	40	90
25	0.8	45	60	45	60

emissions contained about 2 ppmv of hydrocarbons, methanol about 8 ppmv, and natural gas about 200 ppmv (all fuels were dry and emissions corrected to 15 percent O_2). Decreasing the load level increased emissions for all fuels. At a 20 MW load, Jet A emissions contained about 3 ppmv, methanol about 15 ppmv and natural gas about 250 ppmv. Water injection in the fuel had the effect of increasing emissions. The increase is apparently less pronounced for Jet A than for methanol. Injecting water with Jet A at weight ratios up to 0.6 still produces less than 5 ppmv both at 20 and 24 MW load levels. Injecting water with methanol at a weight ratio of 0.2 results in hydrocarbon emissions of about 18 ppmv at a 24 MW load level.

Aldehyde Emissions. Aldehyde emissions were measured separately from hydrocarbon emissions during the SCE test. Emissions from methanol were low, ranging from 0.2-2.0 ppmv at 15 percent O_2 in the exhaust gas. For Jet A, emissions were significantly lower than methanol at 0.003-0.050 ppmv; for natural gas emissions were significantly higher at about 10 ppmv.

Solid Particulate Emissions. During the SCE test, solid particulates in the exhaust gas using methanol were measured at 0.003 to 0.005 $lb/10^6$ Btu; emissions for Jet A measured about 5 times as much at 0.022 $lb/10^6$ Btu. For Jet A, it was found that a significant portion (30-50%) of the particulates were composed of sulfates. Since methanol has no sulfur, sulfate particulates were not found.

SO_2 Emissions. Since methanol contains no sulfur except for what is absorbed through co-mingling in transport and storage, emissions will be low. For Jet A fuel, the emissions for 0.1 weight% sulfur are 0.1 lb $SO_2/10^6$ Btu; for natural gas with sulfur compounds in the gas estimated at 10 ppmv (includes odorizing compounds), sulfur emissions are about 0.002 $lb/10^6$ Btu.

Fuel Vaporization Losses. Since methanol has a significantly higher vapor pressure than distillate fuel oils (92 mm Hg vs. 0.1 mm Hg at 68°F), vaporization losses to the atmosphere could be significant if proper precautions are not taken. During the SCE test, it was estimated that 8-10 gallons per day of methanol were lost due to evaporation. The loss was blamed on a faulty seal between the floating roof and the walls of the methanol storage tank. Examination of the interior of the tank at the end of the test showed that almost 3 inches of area between the floating roof assembly and the tank wall around the circumference of the tank were exposed to the atmosphere. The loss of 8-10 gallons represents about a 0.05 percent loss of total methanol. However, it should be noted that methanol is less reactive to produce ozone than evaporated distillate oil.

d. Safety. Some of the properties of methanol require that special fuel handling precautions be made. These properties are compared with Jet A fuel in Table 9-15. The wide flammability limits of methanol indicate that special precautions for startup and shutdown should be considered.

Table 9-15. COMPARISON OF PROPERTIES OF JET A FUEL AND METHANOL

	JET A	METHANOL
Flammability Limits (% by volume in Air)	1-10	6.7 to 36.5
Flash Point (^{o}F)	100 min. by Specification	52
Vapor Pressure (mm Hg @ 68^{o}F)	0.1	92
Autoignition Temperature (^{o}F)	450	725

Explosion proof electrical equipment, turbine casings, methanol vapor detectors and alarms are some of the equipment that may be required. In the SCE test, precautions taken included modifying the turbine enclosure to incorporate a methanol vapor detector and installing a floating roof tank. Startup with methanol was accomplished without any supplementary fuel assist.

e. Equipment Conversion and Costs. The following is a list of new hardware that might be required for conversion of gas turbines to methanol firing:

- Storage with vaporization preventatives (floating roof tank, vapor recovery, blanketing, etc.).
- Explosion proof fuel pump and lubricating system.
- Fuel lines, valves, seals.
- Fuel filter(s).
- Fuel nozzle.
- Combustor can.
- Methanol vapor detection + alarm system.
- Turbine casing.

The fuel storage and delivery system will essentially have twice the capacity of that for a distillate fuel, since methanol has about half the heating value in Btu/gal. Equipment conversion of the gas turbine including the fuel nozzle and combustor will probably involve minimal hardware changes.

For example, in the SCE test, turbine modification was not required since the fuel nozzle had already been adapted for water injection with distillate fuel. Since it is likely that utilities would prefer dual liquid fuel capability and current NO_x abatement is primarily done with water injection, new gas turbine installations will most likely be capable of firing methanol.

It should be noted that while the SCE gas turbine test showed methanol to be a stable fuel for an unmodified FT4C-1 engine, other turbines could require redesign of combustor cans. It has been proposed by Adelman (Ref. 8) that methanol, compared to a jet fuel, has a significantly higher lean flammability limit. In a computer model of a jet aircraft combustor, the lean flammability limit calculated for methanol corresponds to a fuel equivalency ratio of 0.8, while for Jet Fuel it was calculated to be 0.4. (The fuel equivalency ratio is defined as the actual fuel/air ratio divided by the stoichiometric fuel/air ratio.) The lean limits were determined to give an indication of where the flame would be extinguished. The reason given for the different limits is the higher heat of vaporization of methanol at 463 Btu/lb versus 100 Btu/lb for Jet Fuel.

In a survey done by Badger Plants (Ref. 9), it was estimated that the costs to retrofit a peaking gas turbine for methanol use would be up to 10 percent of the original turbine capital cost of an estimated $300 per installed kW capacity (1981$).

f. Maintenance. Turbine inspection tests in the SCE test program showed that components within the methanol fueled turbine were cleaner than components within the distillate fueled turbine; i.e., a slight carbon buildup was found on the fuel nozzles of the distillate turbine but not on the methanol turbine. From performance data and the turbine component conditions after inspection, UTC personnel estimate that turbine life operating on methanol fuel would exceed the life operating on distillate fuel but probably not exceed the life operating on natural gas. Since turbine life is generally doubled when natural gas is used instead of No. 2 distillate, the use of methanol could probably double the turbine life also. The typical operating life is 1000 hours for the hot-section parts of a turbine burning oil.

In the Badger survey (Ref. 9), it was estimated that the operating and maintenance costs would be about the same or possibly five-to-ten percent lower for methanol-fueled turbines than for conventional-fired turbines.

2. Utilization of Methanol in Boilers

a. Performance. The key performance features for methanol as a fuel for boilers are efficiency and existing facility power rating.

Efficiency. Performance tests have been made as follows:

- Coen Company test at Burlingame, California in December, 1971.

- Central Research Institute of the Electric Power Industry (CRIEPI) of Japan in a test furnace in the mid 1970's.
- New Orleans Public Service, Inc. test at the A. B. Patterson steam generating plant in New Orleans, Louisiana, in 1975.
- Environmental Protection Agency (EPA) sponsored tests for industrial boiler applications in 1976.
- SCE tests at the Highgrove Station in 1981.

Table 9-16 gives a summary of the boiler tests. Boiler efficiencies when using methanol are lower than for heavy fuel oil by 6-8 percent and lower than for natural gas by 2-5 percent. Part of the difference in the efficiencies is due to higher latent heat losses from the water vapor in the flue gas when using methanol compared to the other fuels as illustrated in Table 9-17. Methanol's latent heat loss is equivalent to 12 percent of its Higher Heating Value (HHV) while the loss with natural gas is about 9 percent and with fuel oil about 6 percent. This inherent efficiency loss when using HHV as a basis must be accounted for in fuel cost estimates, since costs are often quoted in terms of dollars per million Btu of HHV.

The other major contribution to the difference in efficiencies is flue gas sensible heat loss. For stoichiometric firing, it can be seen from Table 9-17 that the flue gas quantity in lbs/10^6 Btu of LHV fired is about 3 percent higher for methanol than for natural gas, and about 2 percent higher compared to fuel oil. Flue gas based on LHV fired fuel is used for comparison here to negate the latent heat losses of each fuel and thereby represents more closely the flue gas quantity at similar boiler heat absorption values. Therefore, on a theoretical basis, methanol boiler efficiencies at the same stoichiometric rates are lower than natural gas and fuel oil, providing the stack gas temperatures are the same.

There has been concern that methanol flames will have poor radiant heat transfer characteristics which would lead to even higher sensible heat losses. In the New Orleans Public Service Corporation test (see Table 9-18), the sensible heat loss was highest when firing methanol, as indicated by the air heater outlet temperature of 315°F for methanol, 258°F for oil and 289°F for natural gas. However, in the Highgrove test, careful measurements in the superheater area found that the gas temperatures for methanol were between those for gas and oil, thus alleviating the concern about substantial heat transfer differences.

Supplying methanol to the boiler as a liquid may not be the most efficient use of the fuel. Methanol, with a boiling point of 148°F, can easily be vaporized with lower level heat to give an increased higher heating fuel compared to the liquid; i.e., the HHV increases from 9,760 to 10,234 Btu/lb and the LHV from 8,580 to 9,054 Btu/lb. It may be possible to use boiler stack gas heat for methanol vaporization, stack gas sensible heat representing about 250-300°F T would be required. Since methanol is a clean sulfur-free fuel, lower stack gas temperatures are possible if the current limitation is based upon avoiding SO_3 corrosion; but there are potential problems in regard to heat exchanger size, cost and pressure drop

Table 9-16. METHANOL BOILER PERFORMANCE TESTS

TEST FACILITY	BOILER DESCRIPTION	STEAM CONDITIONS	BOILER EFFICIENCY	COMMENTS
Coen Co. Burlingame, California	Boiler test stand used for fuel and burner evaluations	not available	not available	Ref. 10
CRIEPI Tokyo, Japan	Test furnace; size rated at about $2/10^6$ Btu/hr heat input	not available	not available	Heat absorption by furnace calculated via exhaust gas temperatures for fuels at 1.5 vol% oxygen (=7% excess air with ref. methanol) Refined Methanol 54% Methanol and other high and low boiling materials 55% Crude Oil 58% Ref. 13
New Orleans Public Service Co. New Orleans, LA (sponsored by several utilities including SCE)	•Babcock & Wilcox R-B95 •425,0001b/hr steam rating for net summer rated 49 MW capacity. •Balanced draft •Flue-gas bypass for super heat control. •6 Peabody H-26 burners with center fired gun for oil burning and rings for natural gas, mounted to fire through front wall.	•1385 psig (sat'd) •1310 psig (S.H.) at 955°F	Methanol: 81.8% No. 5 F.O.: 89.6% Natural Gas: 85.6% (efficiencies for 100% load @ 7.2% excess air)	Peabody mechanical atomizing tips tried first with resulting liquid fuel dropping out of cone; steam atomizing tips resulted in high CO concentrations and difficult super heat control; B&W's 80° "Y" tip, mechanical atomizing tips tried with bright sparklers observed at flame intersections only (Ref. 10,11,12)
Highgrove Station Southern California Edison (sponsored by SCE, EPRI and Litton)	•Combustion Engineering wall-fired boiler. •425,000 lb/hr of steam •44.5 MW rating •Balanced draft •Six burners	•1250 psig, 950°F	•Gross heat rates at maximum load. -Low-S residual oil: 10,500 Btu/kWh -Natural gas: 10,900 Btu/kWh -Methanol 11,100 Btu/kWh -Methanol/5% water 11,300 Btu/kWh	Reference 14 Heat rates vs. load are shown in Fig. 9-3.

Table 9-16. METHANOL BOILER PERFORMANCE TESTS (continued)

TEST FACILITY	BOILER DESCRIPTION	STEAM CONDITIONS	BOILER EFFICIENCY	COMMENTS
EPA Sponsored Tests a) Firetube	oBuilt by Superior Combustion oForced draft o4 horizontal passes: -1 radiant pass -3 convection passes oCenter fired liquid burner with air atomization. oRated at 12,000 lb/hr steam at 250 psig.	250 psig	Methanol: 74% Ref. 15,16 No. 5 Fuel Oil: 82% Nat. Gas: 77% (efficiencies @ 5% excess oxygen and various loads)	
b) Watertube Boiler	oBuilt by Superior Combustion oForced draft o2 horizontal passes: -1 radiant pass -1 convection pass oRegister type burners; center fired liquid burners with steam atomizer tips. oRated at 25,000 lb/hr steam at 250 psig o"D" type steam riser/ header configuration	250 psig	Methanol: 75% Ref. 15,16 No. 5 Fuel Oil: 82% Nat. Gas. 77% (Efficiencies @ 5% excess oxygen and various loads)	

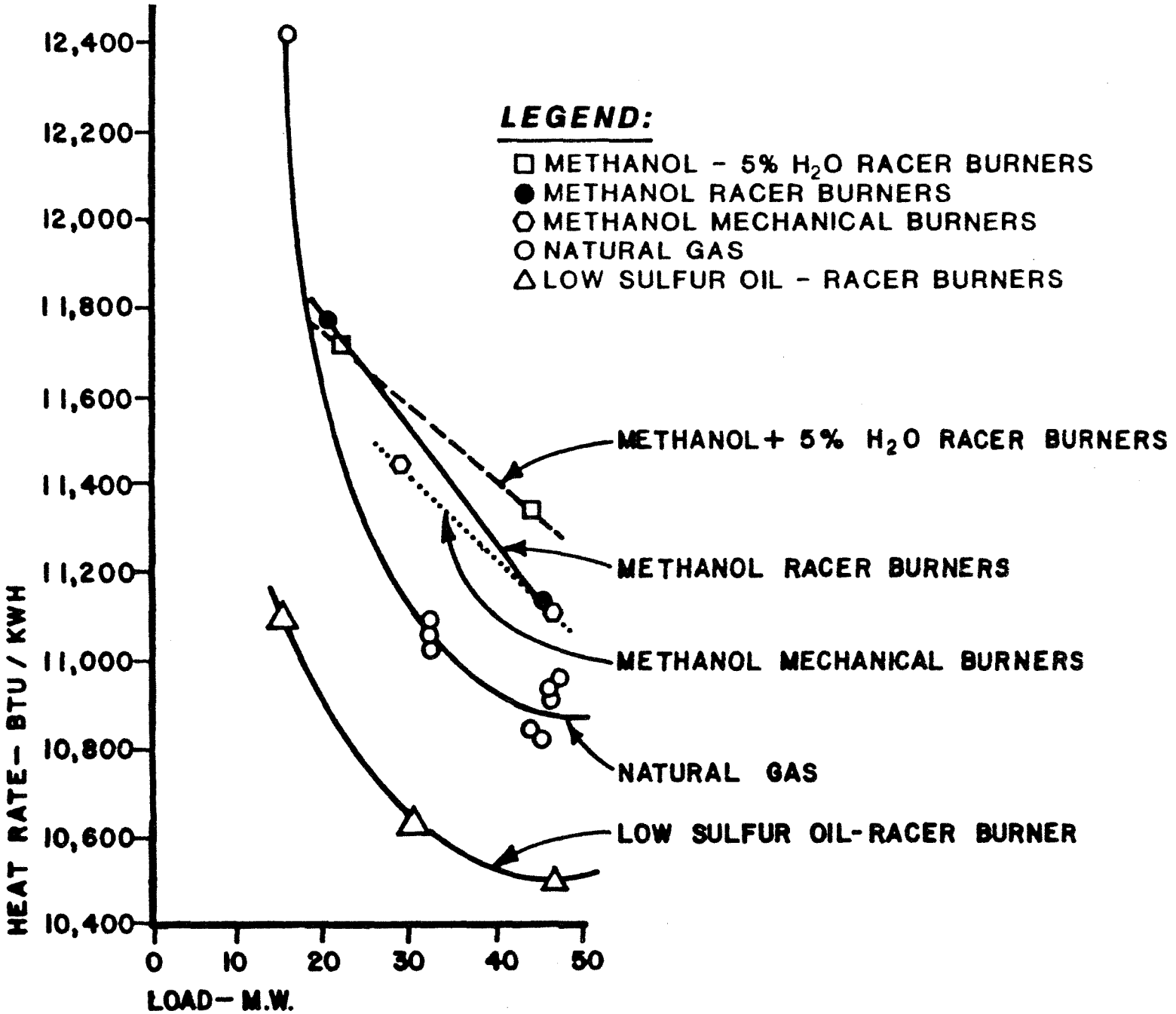


Figure 9-2. HEAT RATE CURVES (Ref. 14)

Table 9-17. COMPARISON OF BOILER FIRING WITH METHANOL, NATURAL GAS, AND FUEL OIL

	METHANOL	NATURAL GAS (as 100% CH_4)	FUEL OIL (C/H = 0.6)
HHV (Btu/lb)	9760	23,879	19,000
LHV (Btu/lb)	8580	21,520	17,860
HHV Fuel Fired:			
(lb/10^6 Btu HHV Fired)	102.5	41.9	52.6
(lb/mm Btu LHV Fired)	116.7	46.5	56.0
Stoichiometric Dry Air:			
(lb/mm Btu HHV Fired)	658.9	717.6	748.6
(lb/mm Btu LHV Fired)	749.5	796.3	796.4
Flue Gas:			
(lb/mm Btu HHV Fired)	761.4	759.5	801.2
(lb/mm Btu LHV Fired)	866.2	842.8	852.4
Moles Flue Gas:			
(moles/mm Btu HHV Fired)	27.6	27.5	28.3
(moles/mm Btu LHV Fired)	31.4	30.5	30.1
Water in Flue Gas: (Wt%)	15.1%	12.4%	7.2%
Latent Heat Loss:			
(% of HHV Fired Fuel)	12.0%	9.8%	6.0%
(% of LHV Fired Fuel)	0%	0%	0%

Based on stoichiometric firing - zero excess air.

and explosion hazards. A more likely approach would be the use of steam extraction for vaporizing the fuel. It has been estimated (Ref. 17) that this would improve the heat rate by 4 percent at the cost of a 3 percent plant derating.

Power Rating. Maintaining plant rating when firing methanol has also been a matter of concern. In the Highgrove test, the maximum output when firing methanol was about 5 percent lower than for oil or gas. This was traced to the capacity limits of the induced draft fan and was due in part to air leakage upstream of the fan. It is believed that these problems will not be found in modern positive pressure boilers with forced draft fans, and that power rating of the modern units would not be compromised.

In firetube industrial boilers which rely more on radiant heat transfer, the effect of methanol's lower flame temperature on boiler performance may be more pronounced (see Table 9-19).

Table 9-18. PERFORMANCE TEST AT NEW ORLEANS PUBLIC SERVICE CORP. FACILITY (Ref. 11)

	METHANOL	OIL	GAS
Gross Generation, MW	51	52	51
Steam Flow, 1,000 lbs/hr	426	432	431
Fuel Flow, 1,000 lbs/hr	60.7	30.8	24.6
Combustion Air, 1,000 lbs/hr	471	519	406
Excess Air, %	26.3	35.6	9.5
Final Steam Temperature, ^{o}F	950	950	940
Superheater Outlet Pressure, PSIG	1,250	1,240	1,250
Air Heater Inlet Temperature, ^{o}F	715	613	690
Air Heater Outler Temperature, ^{o}F	315	258	289
Economizer Inlet Temperature,* ^{o}F	337	345	324
Economizer Outlet Temperature,* ^{o}F	516	497	477
Efficiency	81.8	89.6	85.6
* Water Side			

Table 9-19. PERCENTAGE OF TOTAL HEAT REMOVED IN THE RADIATION SECTION OF A FIRETUBE BOILER (Ref. 15)

SECTION NO.	METHANOL	RESIDUAL OIL
1	2.5	11.1
2	4.5	10.5
3	5.1	7.4
4	3.1	3.0
5	4.2	2.5
6	4.2	1.9
Total	24.6	36.4
Section 1 is closest to the burner, etc.		

b. Fuel Requirements. Since methanol is such a relatively clean and pure boiler fuel, no special specifications are deemed applicable except a minimum methanol content and a maximum water content. The Highgrove test included runs where 5 percent water was added to the methanol with no adverse effects other than a slight decrease in heat rate.

c. Emissions. Emissions considered here from the use of methanol as a boiler fuel include NO_x, CO, hydrocarbons, aldehydes, and solid particulates in the exhaust gases and methanol from fuel vaporization losses.

NO_x Emissions. Emissions data for methanol reported from the boiler tests at the New Orleans Public Service Co. test showed significantly lower NO_x emissions than with fuel oil but only slightly lower than that for natural gas. Emissions were measured at various unit load rates as shown in Table 9-20.

Emissions data reported from CRIEPI (ref. 13) under conditions of about 1 percent oxygen in the flue gas (5% excess air) showed extremely low NO_x emissions of about 15-30 ppmv compared to emissions from residual fuel of about 180 ppmv. Testing of methanol was done with several burner types, including steam atomizing, pressure atomizing and ultrasonic air atomizing burners. At 2 percent oxygen and below, steam atomization produced the lowest NO_x emissions with methanol and ultrasonic air atomization the highest.

EPA sponsored tests (Ref. 15) that were run at about 5 percent excess oxygen in firetube and watertube industrial sized boilers gave the results shown in Table 9-21. EPA testing also included boiler modifications, such as

Table 9-20. NO_x EMISSIONS AS LBS/10^6 Btu HEAT RELEASED (Ref. 10)

UNIT LOAD 100% = 49MW	FUEL OIL	NATURAL GAS	METHANOL
50	.20	.09	.08
75	.22	.12	.11
100	.26	.19	.18

Table 9-21. NO_x EMISSIONS AS PPMV (Corrected to 0% O_2)

BOILER TYPE	NO. 5 FUEL OIL	NATURAL GAS	METHANOL
Firetube	220	100	70
Watertube	170	70	20

flue gas recirculation and staged combustion, designed to investigate how each could be used to reduce the NO_x emissions. It was found that for natural gas fired package boilers, NO_x emissions could be reduced to very low levels (approximately 20 ppmv corrected to zero percent oxygen) by boiler flue gas recirculation, which is less than NO_x from methanol without recirculation. Methanol NO_x could be reduced to about 10 ppmv with flue gas recirculation. Flue gas recirculation for No. 5 fuel oil (ranging from 0.04 to 0.12 weight% nitrogen) was much less effective and resulted in NO_x emissions of about 150 ppmv. However, staged combustion of fuel oil reduced NO_x emissions around 50 percent. No data is available from staged combustion with methanol.

In the Highgrove test, the NO_x emissions for methanol firing were substantially lower than both oil (0.2 %N) and natural gas, although the emissions for gas were unusually high (see Figure 9-3). Adding 5 percent water to the methanol further reduced NO_x emissions by 25 percent at full load.

In general, all the above data indicates significantly lower NO_x for methanol than for fuel oils and somewhat less than for natural gas.

CO Emissions. Emissions were stated to be "generally" lower for methanol than that observed for the fuel oil and natural gas tests done at the New Orleans Public Service Corp. facility. At 11.1 percent excess air, the CO concentration was measured to be 750 ppmv; all other runs made with methanol measured less than 100 ppmv.

Emissions from CRIEPI boiler testing at 0.2 volume% oxygen in the flue gas (about 1 percent excess air) for methanol were about 1400 ppmv and for residual oil about 800 ppmv. However, at 1 volume% oxygen (or about 5 percent excess air), the CO emissions for both fuels were negligible.

Results from EPA sponsored tests in watertube and firetube boilers showed emissions to be lower than 100 ppmv depending on the quantity of excess oxygen. When excess oxygen approached 1 percent, emission levels increased well over 100 ppmv and in some cases over 1000 ppmv.

At Highgrove, CO concentrations were essentially the same for oil, gas and methanol.

Hydrocarbon Emissions. Results from the New Orleans Public Service Corp. test indicated that there were negligible quantities of hydrocarbons based on spot analyses.

Results from CRIEPI tests indicated hydrocarbon emissions equal to or lower than that produced with fuel oils.

Aldehyde Emissions. Statements from References 12, 13, and 14 indicate aldehyde emissions were as low as with other fuels such as natural gas or fuel oils. Aldehyde concentrations measured at Highgrove were less than 1 ppm.

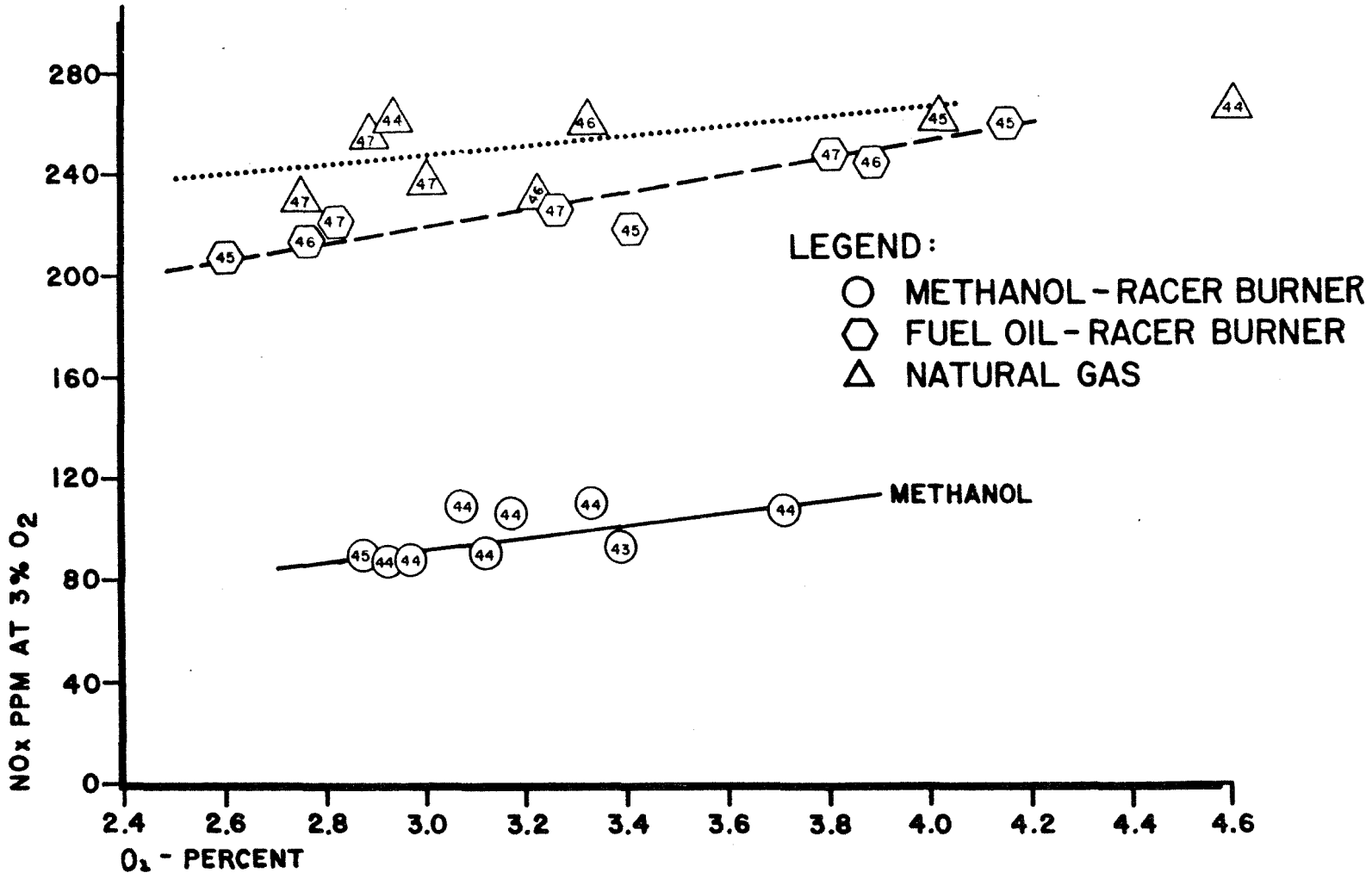


Figure 9-3. NO_x VS O_2 - METHANOL - FUEL OIL - NATURAL GAS
FULL LOAD AS INDICATED IN SYMBOLS (Ref. 14)

Solid Particulate Emissions. Particulate emissions from tests indicated very low emissions. Smoke or soot generation from methanol is expected to be very low compared to other fuels. In the New Orleans Public Service Corp. test, high excess air levels of over 30 percent for No. 5 Fuel Oil were required to maintain a clean stack while methanol tests with excess air below 15 percent always produced a clean stack. At Highgrove, particulate emissions were about half those for oil.

d. Safety. Similar precautions for gas turbine methanol use will be required for boiler fuel use. In the New Orleans Public Service Corp. and Highgrove tests, liquids handling precautions were taken, such as prohibiting plant personnel from smoking around the tank area, loading dock and pump pits, and adding purge and fire control systems.

e. Equipment Conversion and Costs. In burning methanol in utility industrial boilers, the following general areas require new hardware in order to utilize methanol:

- o Transportation equipment to the fuel storage system.
- o Fuel storage.
- o Pumps, lines, valves for delivering methanol from storage to the boiler.
- o Boiler modifications such as different burners, atomizers, plus possible redesign of convection section, air fans, etc.
- o Boiler control modifications.
- o Additional safety requirements.

More than twice the volume of fuel is required when using methanol instead of oil. The major cost component, making up about 50 percent of the total retrofitting cost for converting existing boilers, is the cost of fuel storage. Using the guideline of a total fuel storage requirement of 3 bbls of fuel oil per kW of plant capacity, a 400 MW unit plant would require a fuel oil storage capacity of 1,200,000 bbls; methanol would require storage of about 2,800,000 bbls, or a difference of 1,600,000 bbls. additional storage capacity if the existing fuel oil storage can be converted to methanol storage. Three barrels of fuel oil per kW of plant capacity equates to a 60-90 day storage capacity. Total installation costs for seven 250,000 bbl. tanks are estimated to be about $8 million in mid 1981 (Ref. 18). Total retrofitting costs would be on the order of $16 million for a 400 MW plant which equates to $40/kW of installed capacity.

f. Maintenance. Maintenance of boilers using methanol is expected to be less expensive than for oil-firing, and about the same as for natural gas. Since soot and sulfur problems are considerably reduced, even compared to natural gas, there could be a small maintenance cost advantage in

the boiler area. In addition to the cost savings, the availability of a boiler firing methanol would be improved.

3. Dual Fuel Applications

Dual fuel firing, i.e., simultaneously firing two different fuels through different burners in a multiburner boiler, has recently been identified as a promising application for methanol. Small-scale tests have indicated that firing methanol above fuel oil, with appropriate stoichiometry adjustments, can provide NO_x emission reductions far out of proportion to the fraction of methanol used, e.g., substituting methanol for 20 percent of the oil has reduced NO_x emissions by up to 40% (Ref. 19). Firing methanol above gas may also be beneficial.

Similar effects can be achieved by firing gas over oil; tests by SCE at the Highgrove and Alamitos stations (data not released for publication) have shown very promising results.

There is also some indication (Ref. 28) that methanol use in dual fuel firing can result in a boiler efficiency improvement, on the order of 2 percent improvement for 10 percent methanol. This could lead to payment of a premium for methanol on the order of 20 percent of the fuel price.

Dual fuel firing with methanol may merit serious consideration if pressures for emission reductions increase but the price of methanol remains higher than that of oil. The low emission benefits of methanol could be realized with a relatively small increase in total fuel costs and with low implementation costs.

It should be noted that dual-fuel firing has been investigated only for wall-fired boilers and not for tangential firing. A substantial majority of California utility boilers are wall fired.

4. Repowering Utility Steam Plants

a. Description of Repowering. Repowering may be described as the modification of an existing steam turbine power plant by addition of a combustion gas turbine and the mechanical and thermal integration of the gas and steam turbine systems. There are many ways of integrating a combustion turbine into an existing steam turbine plant including:

(1) Addition of a supplementary boiler between the gas turbine and existing boiler to cool the turbine exhaust prior to reaching the windbox.

(2) Addition of a high temperature, high volume windbox to the existing boiler between the gas turbine and existing boiler, capable of handling the turbine exhaust.

(3) Addition of a boiler feedwater heater after the gas turbine.

(4) Replacement of the oil- or gas-fired boiler with a waste heat boiler to generate steam from the turbine exhaust (applicable to repowering of older, lower pressure and temperature plants).

Westinghouse Electric Corp. has recently completed a study which favored option number (1) for modern reheat steam plants (Ref. 17).

b. Incentives for Repowering. Some of the reasons for repowering a steam plant are as follows:

(1) Efficiency gain from simple cycle to combined cycle operation.

(2) Increase in plant capacity at the existing site.

(3) Reduced lead times relative to new plant construction due to plant siting, permits, and construction considerations.

(4) Minimal environmental impact possible with repowered plant.

(5) Increase in generating capacity without necessarily increasing the cooling water requirement.

(6) Boiler plant in need of extensive overhaul or replacement.

(7) Air pollution difficulties at existing plant.

(8) Low installation cost per added kW capacity.

c. Repowering Cost and Performance. The Westinghouse study evaluated several options for repowering a modern reheat steam plant (specifically PG&E's Contra Costa #6 plant). Results for the options of principal interest are summarized in Table 9-22. Westinghouse predicts very

Table 9-22. REPOWERING COST AND PERFORMANCE FOR CONTRA COSTA #6

	EXISTING SYSTEM			WESTINGHOUSE CASE NUMBER			
	OIL	GAS	METHANOL	5	6	9	10
Fuel Flow (lb/sec)							
Boiler:							
Residual oil	36.6	--	--	36.6	0	24.6	12.3
Methanol	--	--	76.9	0	76.9	25.3	50.8
Comb. Turbine Methanol	--	--	--	37.9	37.9	37.9	37.9
Net Power (MW)	343	343	343	465	466	465	466
Heat Rate (Btu/kWh)	9100	9500	9700	8300	8700	8400	8550
NO_x Emissions (lb/MWh)	2.9	1.9	0.6	1.7	0.4	1.1	0.7
Repowering capital ($10^6$$, 1983)	--	--	10	119	127	127	127
New Generation Cost (1983$/new kW)				980	1030	1030	1030

low total NO_x emissions for the cases which rely primarily on methanol. Thus, methanol-fueled repowering could provide new capacity while simultaneously reducing total NO_x and SO_x emissions at an existing plant, and would therefore be likely to survive any environmental challenge.

d. Cost Comparisons for New Generating Capacity Options. Because of the advantages of methanol-fueled repowering identified above, it is necessary to understand how the various repowering options compare with other options for adding new generation capacity. The ESEA model (described in Section D-5 below) was used to estimate life-cycle costs for the various options using financial parameters from Ref. 26. Results are presented in Table 9-23. Data inputs were taken from the following sources:

-Capital and operating costs for repowering	-Westinghouse study (Ref. 17)
-Capital and operating costs for other options	-SCE CFM IV inputs (Ref. 26)
-Methanol cost	-Chapter 4
-Oil, gas, and coal costs	-Summary
-Nuclear fuel cost, performance data, financial parameters	-SCE CFM IV

Table 9-23 indicates that repowering has lower capital cost than most of the other options for capacity addition, but that levelized electricity costs are substantially higher than for other baseload options. In the high oil price scenario (described in the Summary Report), repowering with methanol may have an advantage in cost of electricity (as well as an environmental advantage in some cases) relative to continued operation of existing units on oil or gas.

5. Methanol Utilization in Methanol Fuel Cells

Fuel cells are electrochemical devices which convert chemical energy directly into electrical energy. This is in contrast to conventional electricity generators which convert chemical energy to heat energy to mechanical energy to electrical energy. One of the advantages of using fuel cells to generate electrical energy is that they require a relatively low fuel heat rate over a wide range of rated power loads (see Figure 9-4). Furthermore, fuel cells enjoy a fairly constant and high system efficiency over an extensive power output range compared to traditional prime movers.

Fuel cells are made up of electrodes, electrolyte, and cooling plates which are sandwiched together to form "stacks". Chemical fuels are "burned" with air to produce electricity directly. The anode is the fuel electrode and the cathode is the air electrode. A schematic portraying a typical fuel cell system is illustrated in Figure 9-5. First generation fuel cells use phosphoric acid as the electrolyte and operate at temperatures (around 200°C) controlled by coolant passing through the stack. Second generation fuel cells will employ a molten carbonate electrolyte and operate at temperatures near 600°C.

a. First Generation Fuel Cells. Phosphoric acid fuel cells, despite continued research, have not been able to operate efficiently on

Table 9-23. COST COMPARISONS FOR NEW GENERATION OPTIONS

OPTION	CAPITAL COST (1981 $/new kW)	REAL LEVELIZED BUSBAR ELECTRICITY COST (1981 ¢/kWh)	
		BASELINE SCENARIO	HIGH OIL PRICE SCENARIO
EXISTING STEAM TURBINE			
Residual Oil	-	9	15
Natural Gas	-	9	14
Methanol	-	12	14
EXISTING COMBINED CYCLE			
Distillate Oil	-	11	15
Natural Gas	-	8	13
Methanol	-	12	14
NEW COMBUSTION TURBINE			
Distillate Oil	400	16	22
Natural Gas	400	11	18
Methanol	400	16	19
NEW COAL (out of state)	1500	7	9
NEW NUCLEAR	1700	4	-
FUEL CELLS	650	12	16
GEOTHERMAL-FLASH	1450	18	-
WIND	1000	5	-
SOLAR			
Photovoltaics	2450	10	-
Pond	3600	6	-
Tower	2550	8	-
HYDRO (Large)	950	1	-
REPOWERING			
Westinghouse Case 5	840	9	13
Westinghouse Case 6	880	12	14
Westinghouse Case 9	880	10	13
Westinghouse Case 10	880	11	13

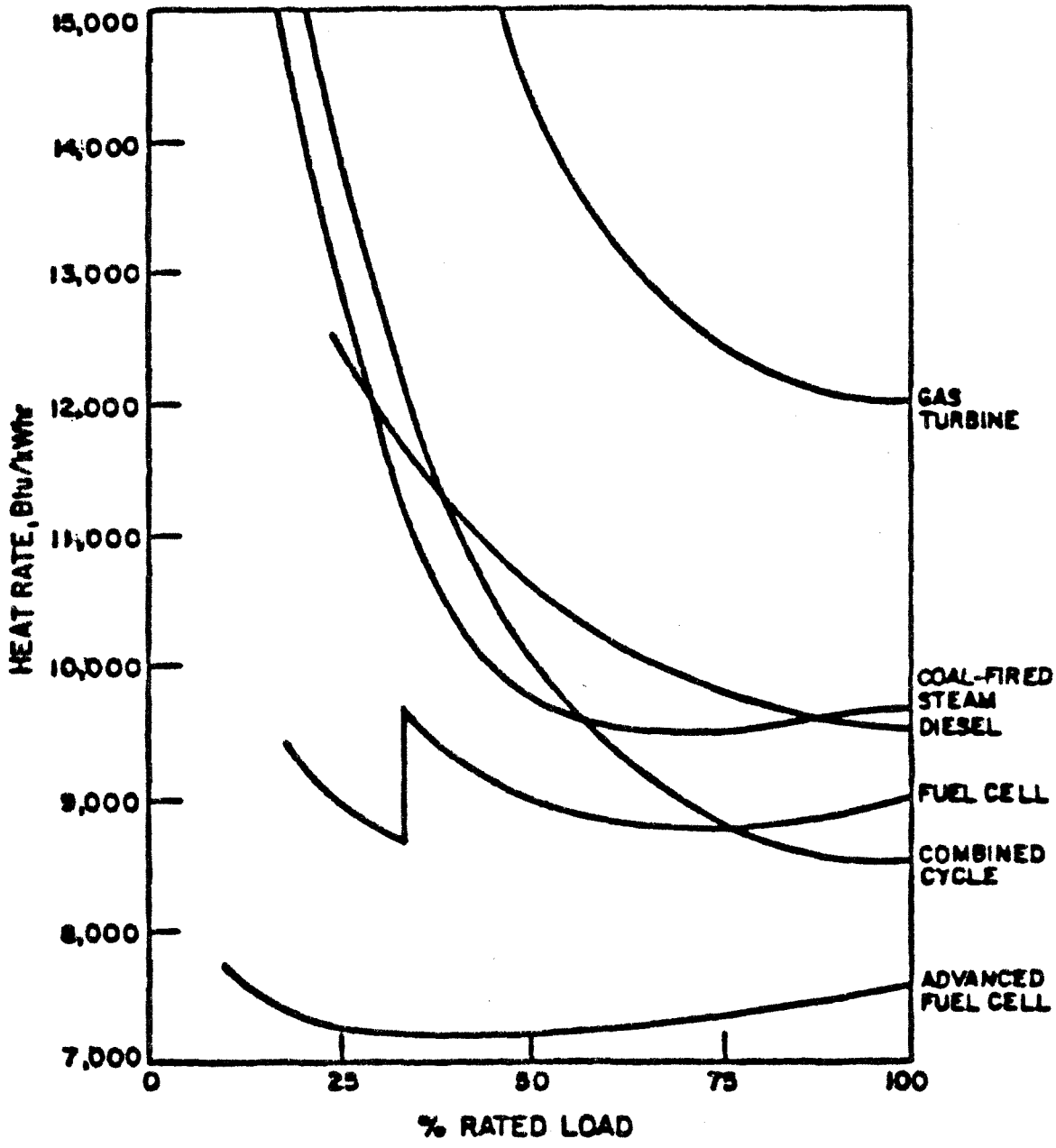


Figure 9-4. COMPARISON OF AC POWER SYSTEM EFFICIENCIES

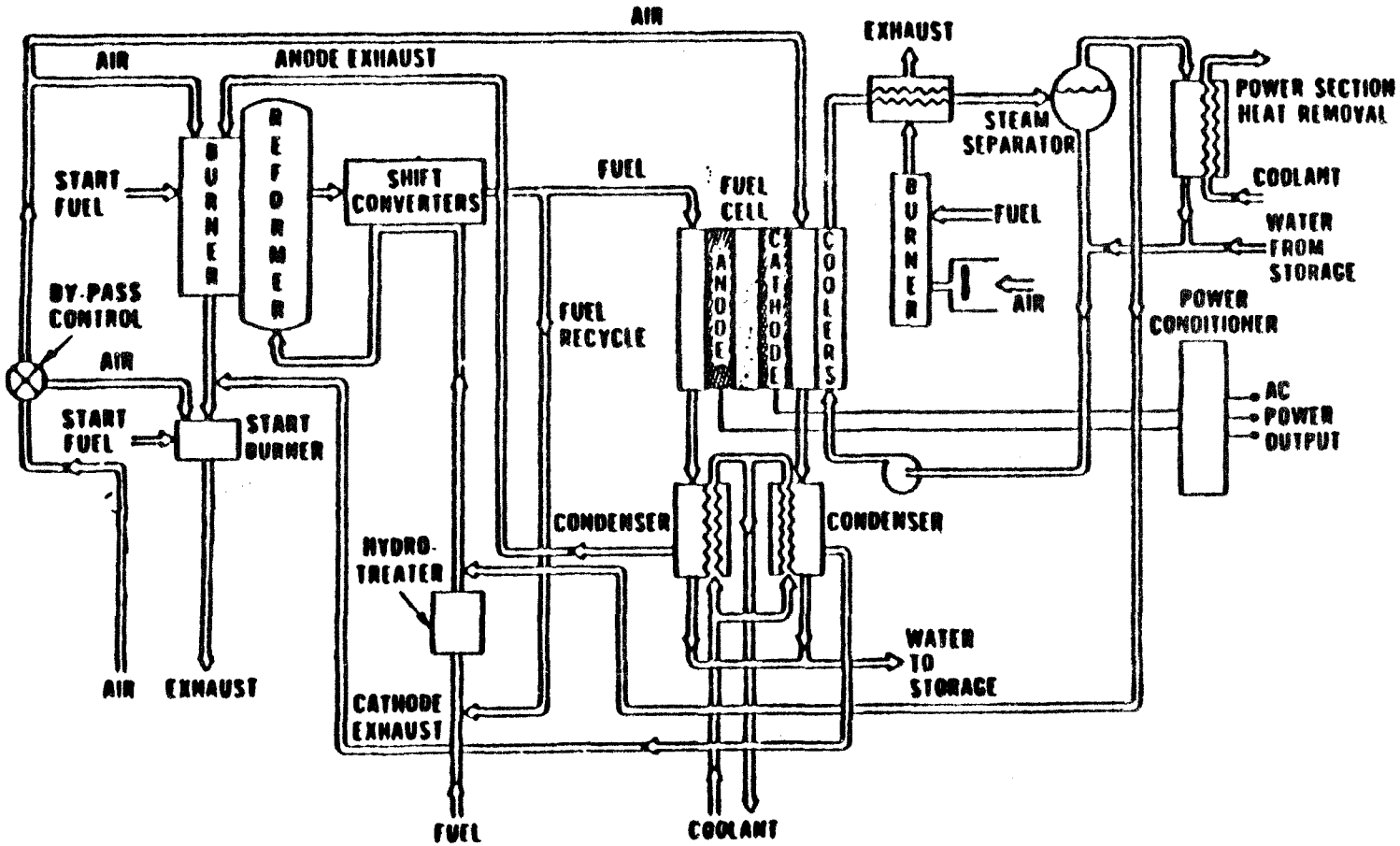


Figure 9-5. FUEL CELL SYSTEM SCHEMATIC

hydrocarbons fed directly to the anode. The direct supply of hydrocarbons to the anode has been attempted without success using the two fuels which have the best potential for direct conversion, propane and methanol. The most efficient operation of phosphoric acid fuel cells is with hydrogen. However, molten carbonate fuel cells will operate satisfactorily on appreciable quantities of carbon monoxide mixed with the hydrogen.

The first generation fuel cell system, by necessity, includes a fuel processor upstream of the fuel cell in order to generate a hydrogen-rich stream for fueling the stack. The requirements of a fuel processor are that it must efficiently convert the hydrocarbon feed into a hydrogen-rich gas with carbon monoxide levels not in excess of 1-2 percent. The efficiency of a fuel processor is defined in terms of both the thermal and conversion efficiencies. High efficiency can most effectively be achieved through the use of easily converted fuels, if possible, and the application of steam reforming.

Steam reforming is an endothermic process whereby a hydrocarbon feed is reacted with excess steam to produce, primarily, hydrogen and carbon monoxide. This is commonly followed by a water gas-shift convertor for reducing the carbon monoxide concentration and increasing the hydrogen concentration. However, the steam reforming of methanol is unique in that the level of carbon monoxide is typically 1-2 percent and requires no shift convertor. A diagram of this type of system is provided in Figure 9-6.

Methanol is particularly well adapted to first and second generation fuel cells because of its efficient conversion. Steam reforming of hydrocarbons or light naphthas requires temperatures of 780 - 840°C, produces methane which reduces the available hydrogen for the fuel cell, requires cleaning of impurities (sulfur and chlorine) from the feedstock, demands 70 percent more steam than the theoretical requirement, and produces carbon monoxide which requires secondary conversion to carbon dioxide and hydrogen. On the other hand, methanol steam reforming requires temperatures around 320°C, produces no methane, requires no pre-cleanup (because of methanol purity), demands 40 percent more steam than the theoretical requirement (nearly one-fourth of the hydrocarbon steam requirement), and produces low concentrations of carbon monoxide, compatible with phosphoric fuel cells. Therefore, a phosphoric acid fuel cell using a hydrocarbon fuel results in approximately 38-39 percent efficiency (heating value of fuel in, to electricity out) compared to 44-45 percent efficiency for such a fuel cell using methanol. This efficiency difference creates great interest for the use of fuel cells in utility systems where electricity is the prime product.

b. Second Generation Fuel Cells. Second generation molten carbonate fuel cells are expected to operate at efficiencies of 45-50 percent using the same fuel processing technology for hydrocarbons as is being developed for phosphoric acid fuel cells. Although steam reforming of methanol offers an improvement in efficiency of phosphoric acid fuel cell operation, a parallel improvement for molten carbonate fuel cells is not expected. This is primarily because the temperature at which the molten carbonate operates (600°C) affords sufficient waste heat to maintain steam reforming at higher temperatures without losses due to heat transfer, control and heat recovery from many different locations within the system. Based on

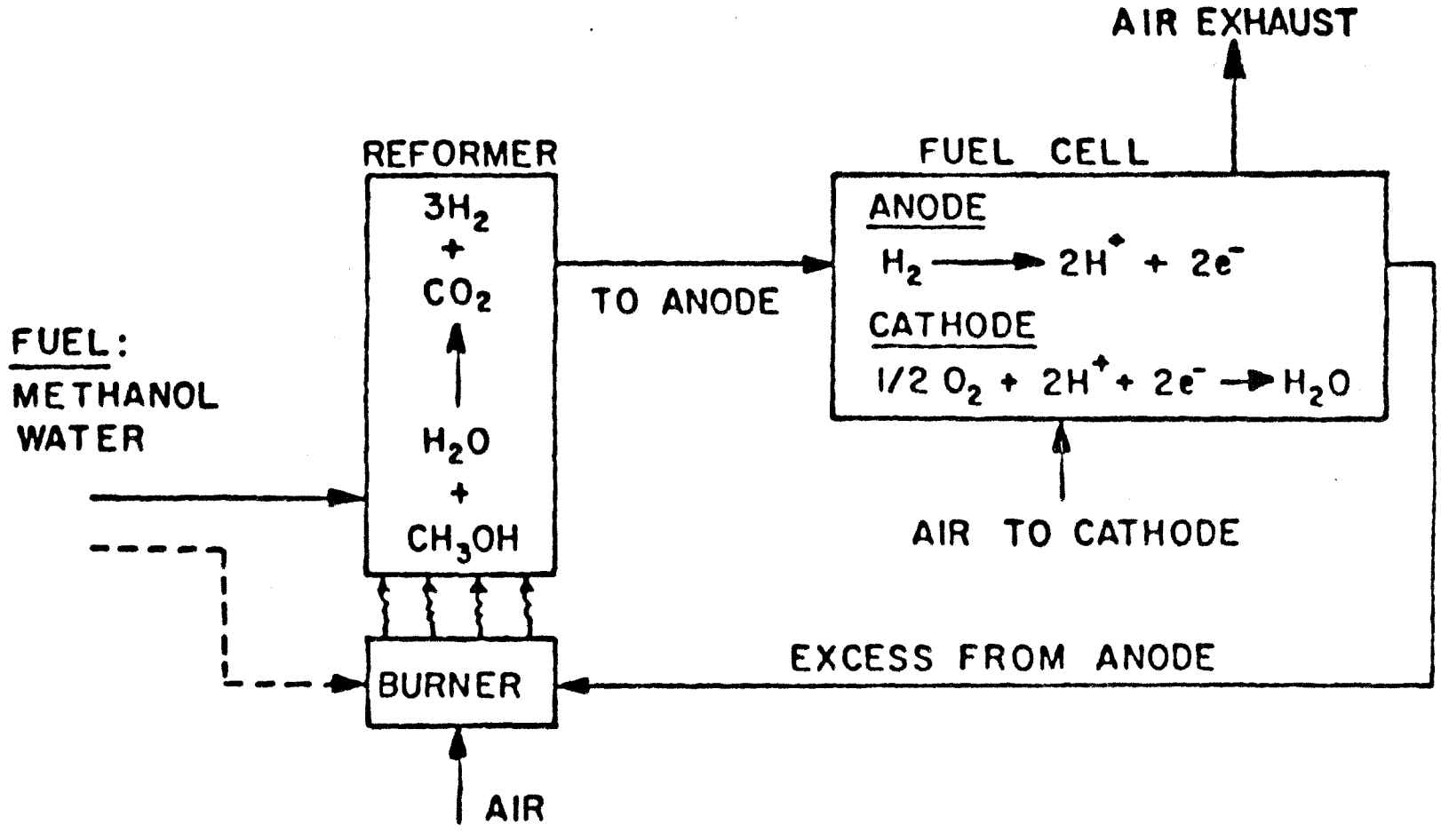


Figure 9-6. REFORMED METHANOL/FUEL CELL SYSTEM (Ref. 8)

recent preliminary tests in which methane was partially steam reformed in or near the fuel cell anode, rather than in a separate steam reformer, the potential for conversion of methanol in like manner would be much greater. Thus, methanol use in molten carbonate fuel cells could conceivably be accomplished more efficiently, perhaps by 5 percent, through the elimination of the fuel processor and achieve conversion directly at the anode. The deciding factors still rest with the scientific advances of this fuel cell to be made in the next ten years.

c. Commercialization. Methanol as a fuel for phosphoric acid fuel cells is mature on a limited basis. The U.S. Army has conducted a program for developing 1.5, 3, and 5 kW fuel cells over the past ten years. United Technologies Corporation (UTC) and Energy Research Corporation (ERC) have been involved in this program and are currently participating in its final stages. UTC is in the process of building 1.5 kW units for field testing in 1982. ERC is designing the 3 and 5 kW units which would lead to field testing in approximately two to three years. Another effort toward developing methanol/phosphoric acid fuel cell systems is underway at Engelhard Industries. This effort is aimed at on-site commercial application in the 50 kW size range. This project is scheduled for a five year development prior to commercialization. Studies conducted by Westinghouse, which is working with ERC, to determine the applicability of methanol/phosphoric acid fuel cells in the size range of 5-10 MW for utilities found a great deal of interest among the utilities and a dearth of information in industry regarding steam reforming of methanol.

All work in the methanol/phosphoric acid fuel cell area has been with chemical or high purity methanol. The main reasons for this are:

(1) It is readily available now and is expected to continue to be.

(2) The projected cost is very nearly that of "raw" or "fuel" grade methanol (although this has not been evaluated in the current study).

(3) The inclusion of processing methanol to chemical grade in new plants is expected.

(4) Chemical grade methanol can be converted at lower temperatures without catalyst degradation than "fuel" grade or methanol contaminated with higher alcohols.

Steam reforming tests were conducted at JPL, UTC, and Engelhard, in which it was found that the temperatures required for high conversion of chemical grade versus fuel grade methanol were much higher for the latter because of the higher alcohol contaminates. Thus, if fuel grade methanol is used for fuel cells, either better catalyst activity will be necessary or lower overall efficiency will be realized due to higher temperature firing of the steam reformer. No deleterious effects of unconverted higher alcohols on the anode have been demonstrated at this time although there is some question concerning sustained activity. In any case, no fuel clean-up is required prior to the steam reformer as in the case of all other fuels.

Methanol is probably the most desirable fuel for fuel cells because of its ease of conversion. In this respect, it can be thought of as an excellent hydrogen carrier. For this reason it would be the most logical fuel if fuel cells were adopted for transportation as well as for on-site and utility use. Both capital costs and inefficient operation would be reduced by this method of electricity production. However, large scale acceptance of both a novel electricity generator and a novel fuel, methanol, may be difficult.

On the other hand, the overall economics of fuel cells are uncertain at this point and the projected high price of methanol has led SCE to use natural gas and naptha as baseline fuels for near-term (10 years) fuel cell applications under study.

D. EVALUATION OF FACTORS INFLUENCING FUEL SELECTION AND FUEL PRICE COMPARISONS

A broad range of technical, regulatory, and financial factors have been evaluated in the investigation of stationary source potential for methanol use. The technical factors can be divided into those related to performance of methanol as a fuel and those involving the logistics of methanol supply. The most important regulatory factors involve rate determination and environmental control. Many of these factors may influence the value of methanol in utility and industrial applications and would thus require correction of its price for purposes of comparison with the prices of competing fuels. These attributes are discussed in this section, and quantitative estimates are provided wherever possible.

1. Performance Factors

Effects of methanol use on efficiency, rating, materials, maintenance requirements, and emissions in boiler and combustion turbine applications have been evaluated in detail above, and the key findings are summarized here.

Performance comparisons for two key parameters, thermodynamic efficiency and NO_x emissions are presented in Figure 9-7. Uncertainties are shown for dual fuel efficiency, where estimated improvements relative to oil firing have not yet been demonstrated, and for NO_x emissions for pure methanol, where combustion techniques have not been optimized.

System efficiencies of combustion turbine generators can be shown analytically to be higher for methanol than for oil or gas. This was confirmed by SCE tests at the Ellwood Station which showed improvements in heat rate at constant NO_x emission levels on the order of 2 percent. For boilers, it has been found that heat rates for methanol, as measured in terms of higher heating values of the fuels, are 2-5 percent worse than for natural gas and 6-8 percent worse than for oil.

With appropriate injector changes, SCE had no trouble in maintaining the system rating in the turbine tests. In the boiler test at Highgrove, however, it was found that derating was necessary because of the inability of the fan to maintain the increased stack gas flow for methanol combustion. This fan limitation is believed by SCE to be peculiar to balanced pressure units such as Highgrove and not applicable to most of their modern steam turbine units which use positive pressure boilers.

Some materials used in existing fuel pumps and supply systems may not be compatible with methanol or may be inadequate for the increased volumetric flows. The cost of modifying these systems does not appear to be substantial, but this should be verified by a detailed study.

It has been suggested that methanol-fired systems will require less maintenance than oil-fired systems because of clean-burning characteristics of methanol. Long duration tests necessary to confirm this have not been run, but SCE engineers have confirmed that in terms of deposition and corrosion in

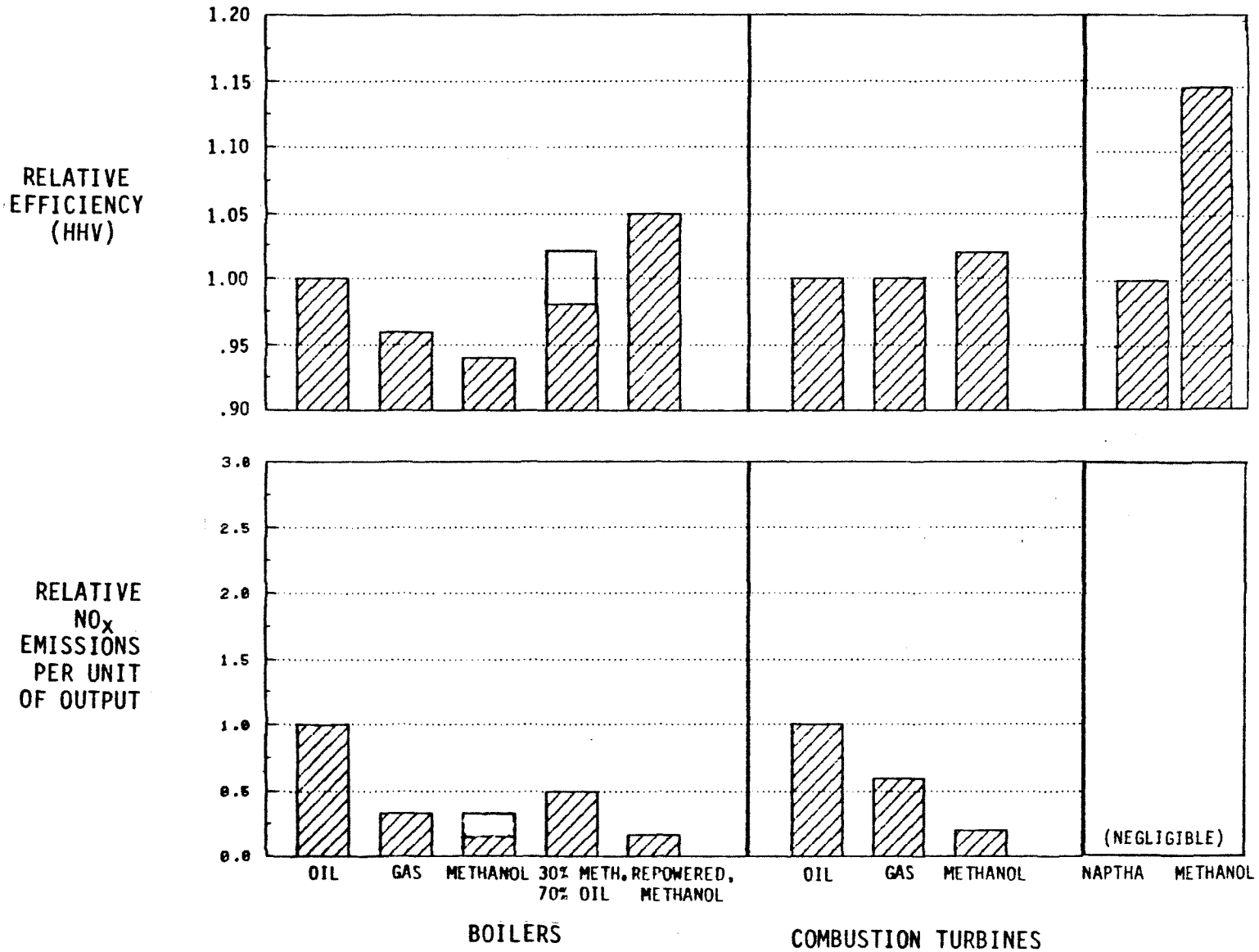


Figure 9-7. BOILER AND COMBUSTION TURBINE PERFORMANCE COMPARISONS

their brief test programs, methanol appears to be no worse than natural gas firing, which requires about half the maintenance as for oil firing.

The various tests have confirmed that, in both boilers and turbines, methanol has NO_x emission levels which are roughly half of those for oil and somewhat lower than for natural gas. Since the methanol production process can be designed to remove practically all of the sulfur and ash present in the feedstock, emissions of SO_x and particulates will be very small.

2. Cost Impact of Capacity Rating and Heat Rate Differences

Evaluation of the impact of heat rate changes on utility system operating costs must take into account not only the changes in fuel costs per unit of output for the generator in question, but also changes in the loading order. An improvement in marginal cost due to methanol firing would lead to increased capacity factors for the units using methanol and a decrease in capacity factors for other units. In addition, the low-NO_x dispatch scheme used by SCE in which units are brought on-line in economic order but then dispatched in order of minimum NO_x emissions, could lead to very high capacity factors for methanol-fired units.

If derating is involved (e.g., fan-limited boilers), it can lead to increased operating costs because of the need to load up more expensive units and may also require capital expenditures to maintain peak capacity reserves and an acceptable loss of load probability (LOLP).

Heat rate related costs and derating operating costs and LOLP impacts were evaluated using the SYSGEN computer simulation (Ref. 22). SYSGEN is a production costing and reliability model of an electric power system. The model determines the conventional plant operating schedules which will meet required loads at minimum cost and estimates the frequency, duration, and probability of loss of load for the given generation mix and customer demand. The program uses a modified Booth-Baleriaux technique which treats plant outages as randomly occuring loads on other plants in the utility system.

To provide an estimate of the impact of derating that might result from large-scale methanol use, a simulation of the 1990 SCE system was run in which a 2 percent derating (a pessimistic estimate of the average influence of fan-limits) was assumed for all steam turbine units, with no change in heat rate or fuel cost per unit of energy. The simulation results showed an increase in busbar energy costs of 0.02 mil/kWh (1981$) and an increase in LOLP from 0.0004 to 0.0006, both of which are considered negligible.

To investigate the effects of heat rate changes, a 1990 simulation was run in which a 2 percent improvement in heat rates for all combined cycle and combustion turbine units was assumed. The result was a negligible decrease in busbar energy cost of a few thousandths of a mil/kWh.

3. Impact of Maintenance Cost Differences

Although no long-term tests have been run to provide definitive data, all of the short-term tests on boilers and turbines have indicated that

fouling and corrosion problems with methanol will be minimal. Thus, maintenance requirements similar to those for natural gas (and substantially less than those for oil) are indicated. When compared with oil firing, cost savings would result both from reduced direct maintenance costs and from improved availability of the methanol-fired units. Since total O&M costs for oil-fired turbine units are on the order of 2 mils/kWh, the direct maintenance cost savings will not be significant. The availability improvement could have a larger impact.

4. Logistics Factors

Supplying methanol to existing power plants and on-site storage may both involve significant impediments to utility methanol use. As shown in Table 9-5, only three of SCE's eight large power plants in southern California can currently be directly supplied by water. The others rely on a network of oil pipelines which connect them with several oil refineries, a number of remote storage sites, and the Long Beach harbor. While it would probably be possible, after some modification, to put methanol through the pipeline network, simultaneous use of both methanol and oil would create problems both in the logistics of batch deliveries and in regard to contamination of one fuel by the other. There are precedents for batching in regard to distillate deliveries to combined cycle plants, but these involved much smaller percentages of the total system capability than if a substantial part of the system were to be converted to methanol. A number of concerns regarding cross-contamination have been raised, possibly the most significant being an increase in vapor pressure of fuel oil requiring expensive air pollution controls for storage facilities. Thus, use of the existing supply infrastructure cannot be assumed without a more detailed investigation.

On the other hand, development of a parallel pipeline system would involve enormous difficulties in obtaining rights of way and permits. Thus, the first units to use methanol would probably be those which could be supplied by water. The others may have to rely on expensive rail transport until an all-methanol system evolved.

The utilities currently have firmly entrenched rules regarding fuel reserves. For example, Edison desires to maintain a level of inventory sufficient to ensure continuity of oil supply for 90 days under conditions of increased demand for oil covering a probable variation in load together with the capability of non-oil generation resources (such as natural gas) to pick up the load. Since methanol has half the volumetric energy content of fuel oil, additional storage tanks would be needed at most stations. Some of the stations would not have room, but it may be posible to substitute system storage. Storage costs appear to be the most significant cost element of the modifications necessary to convert existing units to methanol (see Section C-2 above).

5. Costs of Modification of Existing Facilities

The most significant modification cost would be for increased storage facilities to satisfy reserve requirements. Other costs are associ-

ated with modification or replacement of burners, pumps and plumbing, and addition of safety provisions. Total costs have been estimated as $40/kW for steam turbine units and $15/kW for combustion turbines (see Section C).

The influence of these expenditures on electricity costs was estimated using the Energy Systems Economic Analysis (ESEA) model (Ref. 23). The ESEA program calculates the net present value, breakeven capital cost, and breakeven busbar energy cost (BBEC) of a utility-owned electric plant. ESEA uses a required revenue methodology which treats taxes and depreciation explicitly and allows the inclusion of tax preference in the form of accelerated depreciation and/or an investment tax credit.

The increase in real levelized BBEC due to modification costs with standard utility financial assumptions (see Table 9-24) was estimated to be 1.7 mils/kWh for steam turbines and 0.65 mils/kWh for combustion turbines (both in 1981 dollars). To provide the same levelized BBEC, the price of methanol should be lower than the price of a fuel usable without modification by 0.18 dollars per million Btu (MBtu) for steam turbines and 0.07$/MBtu for combustion turbines.

It should be recognized that this analytical approach is not used by the California Public Utilities Commission (see the following paragraph). Capital expenditures are approved in advance for inclusion in the rate base in the year they are placed in service and can be justified in terms of long-term potential for cost savings. Fuel costs are approved for pass-through on a year-by-year basis; once the modifications have been made, the PUC would not consider the capital-related costs in evaluating a decision to purchase methanol.

6. Rate Regulation

Investor-owned utilities in California (which include PG&E and SCE, but not LADWP) are subject to rate regulation by the state Public Utilities

Table 9-24. ESEA MODEL INPUTS

CONSTRUCTION TIME	1 year
YEAR OF FIRST OPERATION	1985
SYSTEM LIFE	20 years
INFLATION RATES	
General	7.2%
Fuel	8.5%
O&M	9.0%
DISCOUNT RATE	12.0%
TAX RATE	51%

Commission (PUC). The PUC approves new major capital projects in advance, but formal ruling on pass-through of fuel purchase costs to rate payers is not made until after the fact. There is, however, informal coordination in which the PUC can make known the likelihood of approving costs incurred under particular types of procurement contracts. The following paragraphs present highlights of discussions with the PUC staff.

As a result of recent bad experiences with long term take-or-pay oil contracts, the PUC is very strongly against this type of contract. Since the PUC has been considering rejection of pass-through of under-lift penalties in current contracts, the utilities are also wary of such contracts, and it is not likely that a utility would even go to the trouble of proposing a strict take-or-pay contract for methanol to the PUC. This situation is likely to pose severe problems for development of a utility market for methanol, since early suppliers could have trouble finding alternative applications. It may be possible, however, to satisfy the PUC by developing compromise contracts in which the risk associated with an unexpected downturn in demand is shared among the methanol supplier, the utility, and the rate payers.

The PUC adheres to a long-standing policy of not requiring today's rate payers to subsidize future benefits. Thus, a long-term methanol contract with promise of low escalation rates, but with first year costs higher than the spot market price of oil, would be subject to severe attack. This is not to say that such a contract would be rejected out-of-hand. Some small premiums may be allowed by the PUC to pay for benefits such as protection against price escalation, security of supply, and environmental improvements. Tradeoffs of this type are made on a case-by-case basis. Future commissions would not be bound by precedents set by an earlier decision.

In regard to premiums for security of supply, the PUC would tend to favor synthetic natural gas (SNG) over other synfuels because of the Commission's responsiblity for gas supply. (PG&E has expressed a similar preference.) They look upon gas supplies for electric utilities as a cushion against shortages for higher priority gas users (those who have no alternatives).

The PUC is very wary of arrangements that would require rate payers to cover cost overruns on capital intensive projects. A sharing of risk would have to be included in such cases.

Thus, in the forseeable future, near-term cost will continue to be the overriding factor in PUC decisions and premium payments allowed for the benefits discussed below will continue to be modest.

7. Environmental Regulation

It is clear that substitution of methanol for oil in utility applications can lead to substantial environmental benefits as a result of reductions in NO_x, SO_x, and particulate emissions. The value of these benefits to the utilities, however, is not so clear.

Utilities in the South Coast Air Basin (Los Angeles and vicinity) and in the Ventura County Air Pollution Control District--particularly SCE and

LADWP--are required to reduce their NO_x emissions by 60 percent by the year 1990. Use of methanol in some units could be included as part of an overall strategy to satisfy this requirement. This could lead to payment of a premium for methanol as discussed in Section D-10 below.

The South Coast Air Basin Air Quality Management Plan (AQMP), recently adopted by the local agencies (but likely to be rejected by the EPA because it does not provide for meeting Federal standards by 1987) included only one stationary application of methanol, namely use in utility turbines for SO_2 mitigation, in the recommended short-term tactics (implementation by 1987). Methanol use could be a substitute for some of the other recommended short-term tactics such as the requirement to burn oil with less than 0.1 percent sulfur in power plants, but the ability to make such substitutions will depend on the form of the regulations prepared pursuant to the recommended tactics and the value of methanol use in emission control strategies cannot be determined until the regulations are finalized. Use of methanol as an industrial fuel was listed among the longer-term strategies outlined in the AQMP for control of reactive organics, but the total emission reductions available were found to be relatively small.

Methanol may also provide benefits in regard to the "offsets" and "bubble" policies currently being developed by federal, state and local air pollution control agencies. Methanol use could provide offsets to be used for expansion of other facilities or for sale to other companies. Under the bubble policy, burning methanol in one boiler could allow less expensive, higher-sulfur oil to be burned in another boiler. These policies are in their infancy, and there is no precedent that can be used to predict the outcome of their application here. There is concern that once methanol is used successfully at one site, the regulatory agencies will order its use at other sites, thus subsumming offset and bubble benefits.

Methanol could also have some environmental problems of its own. Being more volatile than fuel oil, additional precautions against evaporative emissions in handling and storage could be required (unless it is shown that low photochemical reactivity of methanol balances the increased emissions). Sealing of storage tanks could be very expensive. Further, since most of the existing power plants are in areas within the jurisdiction of the California Coastal Commission, separate permits would be required from that agency. The Coastal Commission would be particularly concerned with the impacts of spills.

8. Value of Environmental Benefits

Methanol use can result in avoidance of costs associated with required addition of emission control equipment and can produce salable offsets. The PUC does not presently have a mechanism for providing credit for such savings, but it is possible that either the legislature or the PUC would develop such a mechanism if the savings appear significant.

The actual savings would depend strongly on the precise terms of the air quality regulations. To establish the order of magnitude of the savings, the ESEA model (see Section D-5) was applied to three cases involving hypothetical regulations for oil-fired steam turbines. The results are outlined in Table 9-25. In all three cases, regulations similar to those assumed are currently

Table 9-25. VALUE OF METHANOL IN AVOIDING ENVIRONMENTAL CONTROL COSTS

Regulation	Reduce NO_x emissions by 50%	Reduce SO_x emissions by 60%
Likely Location	South Coast Air Basin	South Coast Air Basin
Control technology alternative	Add selective catalytic reduction to 2/3 of plants	Burn .1% S Oil in all plants
Methanol Alternative	Burn methanol in all plants	Burn methanol in 60% of the plants
Control Tech. Costs		
Capital(1981$/kW)	110	-
Operating(1981 mils/kwH	3.3	3.2
Value of methanol as Alternative to Control Technology Addition (1981 $/$10^6$ Btu)	0.57	0.56

under consideration in some part of California, although the recent out-of-court settlement of ligitation over NO_x emission reductions in the South Coast Air Basin has reduced the likelihood that selective catalytic reduction will be necessary for NO_x emission control in the near future (see Section D-10). Assumptions in Table 9-24 were used in these calculations.

The value of methanol use in producing salable offsets would be essentially equal to the value in Table 9-25 for avoidance of internal costs by the utility. While these benefits are potentially significant, the utilities tend to discount them because of the possibility that they would vanish if the use of methanol for NO_x emission reduction is incorporated into the State Implementation Plan (SIP). Emission reductions can only be counted as offsets to the extent that they surpass SIP or other regulatory requirements.

9. Value of Increased Capacity for Environmentally Restricted Power Plants

Three modern Southern California power plants are restricted to operate below full capacity in order to limit emissions of NO_x and other pollutants. Firing of methanol in these plants could potentially have lower emissions per unit of generation than either oil or gas and thus permit

increased capacity at these stations (although it is not clear from tests to date how much lower emissions would be for methanol than for gas). Such a capacity increase could result in avoiding increased operation of less efficient units and/or expenditures for new capacity or power purchases and thus could place a premium value on the methanol used. The three environmentally restricted cases are outlined in Table 9-26 and analyzed individually in the following paragraphs.

Ormond Beach is believed to be the most important of the three because of the possibility that dual fueling could eliminate the restriction thus resulting in a large premium payable for methanol. In the past, the Ormond Beach boilers were restricted to operate below nameplate capacity because of high NO_X emissions and also because of vibration. A recent modification to one of the two boilers (a divisionary wall) has eliminated the vibration and reduced NO_X to a level where (after the second boiler is modified) the output would be restricted by NO_X to the levels shown in Table 9-26. It is believed that methanol/oil or methanol/gas dual fueling could permit operation at 1700 MW or possibly higher, although this must be considered somewhat speculative until test data on dual fueling in large boilers is obtained. It should also be noted that gas/oil dual fueling and/or gas/gas burner stoichiometry variations might also permit operation at 1700 MW or higher and thus preclude the payment of a premium for methanol.

Under current conditions of substantial capacity margins, the premium payable for methanol in increasing the capacity of Ormond Beach (assuming that it cannot be increased using non-methanol tactics) can be evaluated in terms of the cost savings resulting from reduced loads on less efficient units. In Figure 9-8 the premium for methanol is expressed in terms of the cost of the conventional fuel in use at the other units, the average heat rate of the

Table 9-26. ENVIRONMENTALLY RESTRICTED POWER PLANTS

POWER PLANT	ORMOND BEACH 1 and 2	SCATTERGOOD 3	LONG BEACH 8 and 9
Estimated actual capacity (MW)	1,700		
Nameplate capacity (MW)	1,500	496	530
Placed in Service	1971	1974	1976
Heat Rate at Full Load (Btu/kWh)	9,066	9,980	9,980
Restriction	1520MW firing oil 1520MW firing gas	no oil firing 284MW firing gas	34% capacity factor
Potential Neat Methanol use (tons/day)	10,700	3,500	3,400
Potential Overfiring (10%) Methanol Use (ton/day)	1,070	350	-

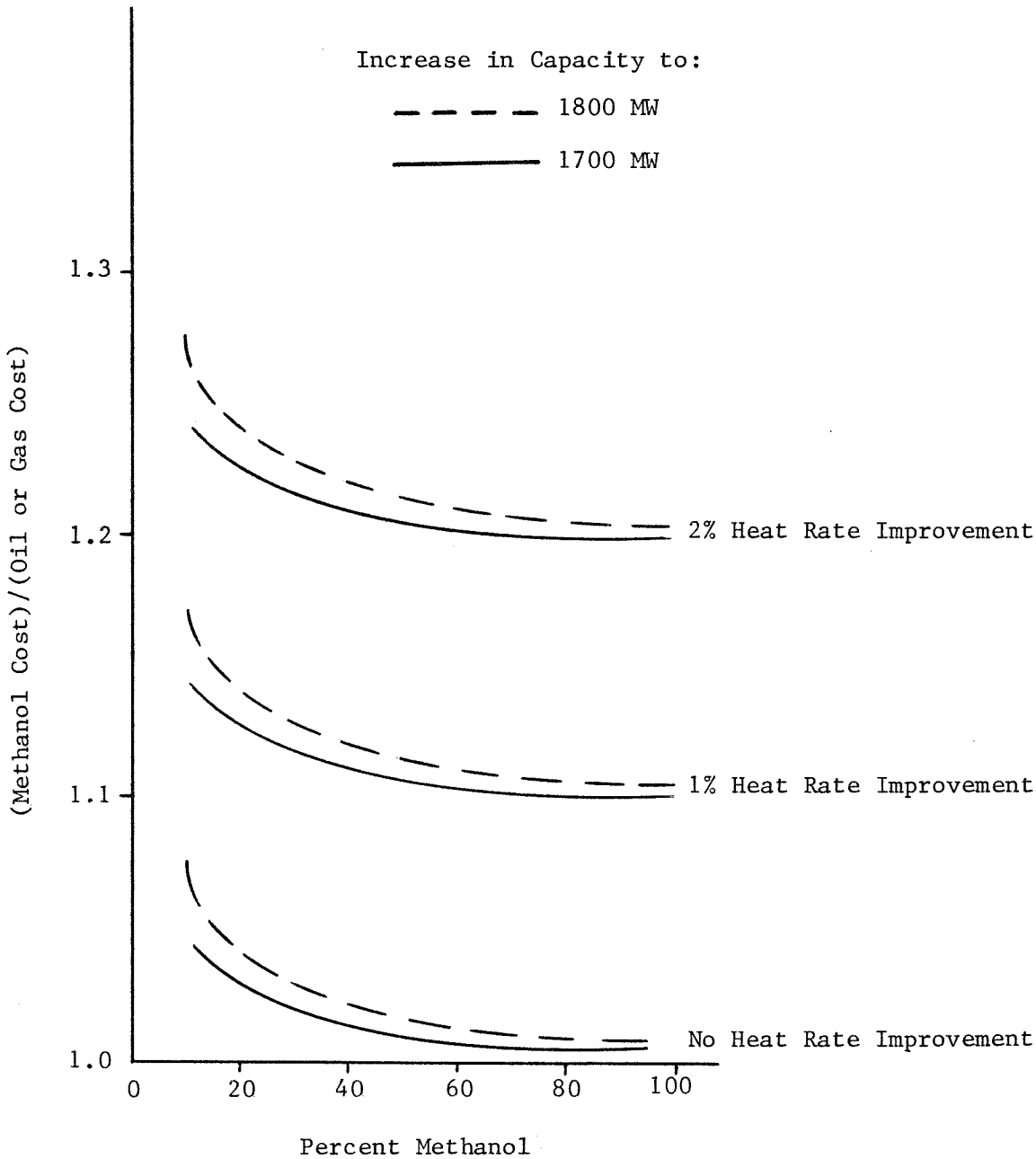


Figure 9-8. NEAR-TERM PREMIUM FOR METHANOL IN INCREASING THE UTILIZATION OF CAPACITY AT ORMOND BEACH*

*Average heat rate of capacity displaced 9500 Btu/kWh

capacity displaced (assumed to be approximately 9500),* the increase in Ormond Beach capacity and the percent of methanol in the dual fuel firing. A 100 percent methanol case is also shown. Under current conditions the unloading would be expected to occur on relatively efficient units, so a likely combination would be a heat rate of 9500, a capacity increase to 1700 MW and a 10 percent methanol mix resulting in premium of about 5 percent of the current oil or gas costs: about $0.25/MBtu. It should be noted that this is in addition to any premium that would be payable as a result of projected efficiency improvements for dual fuel firing (see Section C-3). In order to illustrate the impact of the potential heat rate improvements, two additional sets of calculations are also displayed in Figure 9-8, which show the impact of a 1 percent or 2 percent improvement in the boiler heat rate. It is clear that the value of the potential heat rate improvement dominates the value of using more efficient generating units in the near term, and is necessary if methanol use is to be justified on cost-effectiveness grounds. For example, if the price of oil or gas is assumed to be $6.00/$10^6$ Btu in the mid 1980s (1981 dollars), then in the 10 percent overfiring mode with a 2 percent heat rate improvement and a capacity expansion to 1700 MW the justified premium for methanol is 28 percent, which implies a price of $7.68/$10^6$ Btu for methanol. Although there may be small quantities of subsidized methanol that cost this amount to produce (e.g., methanol receiving substantial tax breaks from bioenergy feedstocks), it is unlikely that the market price would drop this low. As discussed in Chapter 4, the baseline case for methanol production is that the marginal producer in chemical markets will be existing producers using pipeline natural gas (expected operating cost of over $10.00/ 10^6 Btu) and the marginal producer into fuel markets would be based on new remote natural gas projects at an expected delivered cost of $9.00/$10^6$ Btu. Thus, in the near term the potential improvements in efficiency are probably not sufficient to lead to methanol overfiring on a fuel efficiency basis.

In the longer term, less efficient units would be displaced, resulting in higher premiums for methanol, and eventually the increased Ormond Beach capacity would displace power purchases from marginal sources. The premium payable for methanol in avoiding such purchases is shown for the 10 percent dual fuel case in Figure 9-9, as a function of heat rate improvement, capacity increase and cost of purchased power. Purchases under PURPA negotiated on the basis of avoided cost plus capacity credit are currently averaging about 7¢/kWh. Thus, in the case that there is a 2 percent heat rate gain, the avoided cost is 7¢/kWh and the capacity is increased to 1700 MW at Ormond Beach the premium payable for methanol would be $3.00/$10^6$ Btu over the applicable oil or gas price. The value of methanol, therefore, would be $9.00/ 10^6 Btu, which is approximately what its delivered cost to California has been calculated to be based on remote natural gas feedstocks. As shown in Figure 9-9, the actual value of the appropriate premium could be greater or less than $3.00/$10^6$ Btu depending upon the actual heat rate gain achieved

---

*The precise heat rates of the units impacted by expanding an efficient unit in the loading order is a very complicated calculation which would require detailed simulation analysis. Experience with this type of modeling suggests that the largest impact occurs on the units immediately following in the loading order, which would also be quite efficient in this case.

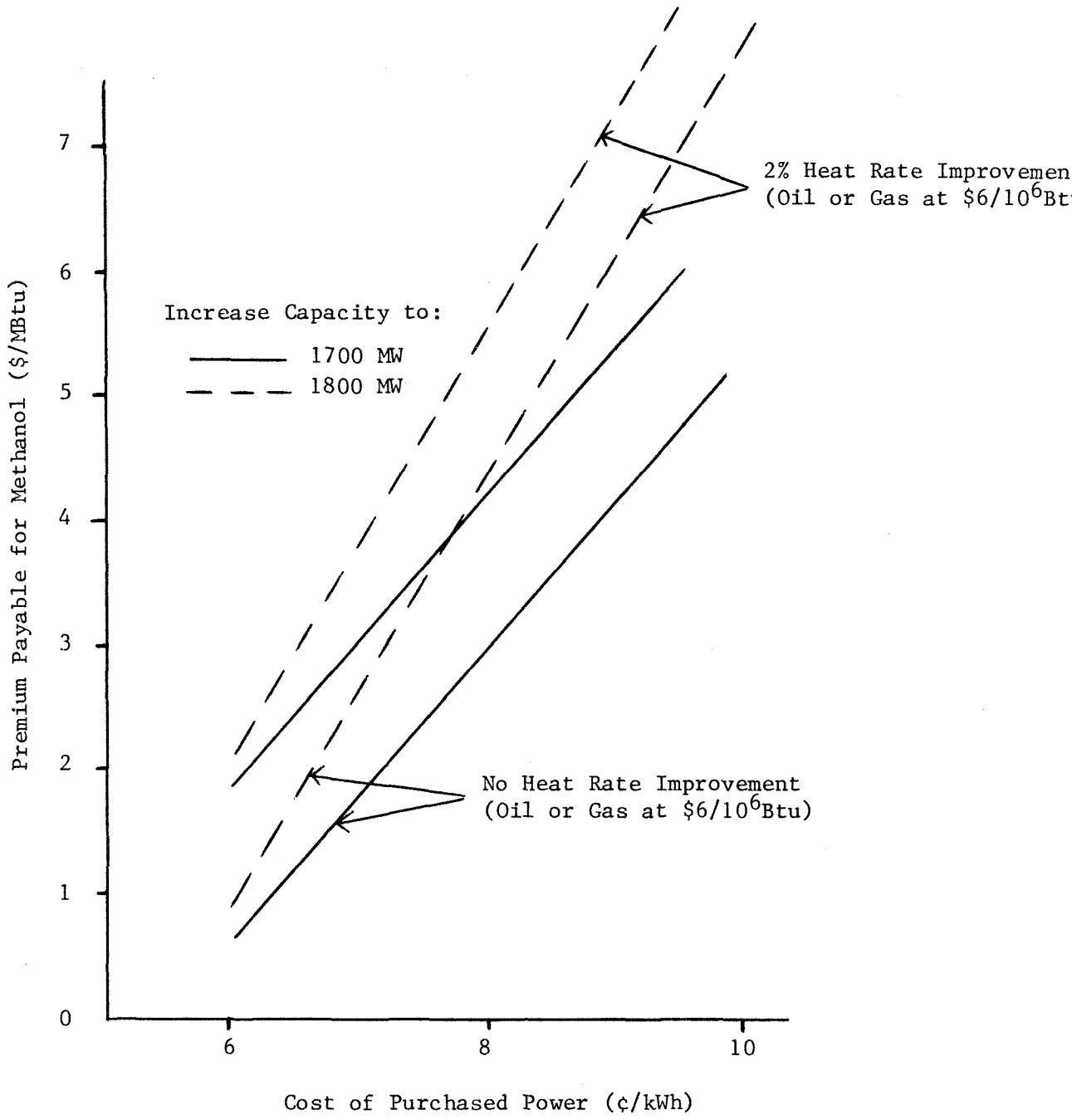


Figure 9-9. PREMIUM FOR METHANOL IN INCREASING CAPACITY AT ORMOND BEACH USING 10% DUAL-FUEL FIRING (1981$)

and the expansion in capacity that would be permitted. These unknowns can only be resolved through a demonstration of methanol overfiring in comparison with natural gas overfiring in a full-scale test. The potential premiums are substantial enough, however, to warrent that the testing be done. Furthermore, if the more optimistic improvements (2% or more heat rate gain and capacity restriction at Ormond Beach relaxed to 1800 MW) are achieved, there would be a viable application for methanol at the Ormond Beach plant.

At Scattergood, an increase to nameplate capacity would require a 40 percent emission reduction compared to gas firing, which may not be achievable by overfiring with methanol. Assuming that the necessary reduction could be achieved, the value of the premium for 30 percent methanol overfiring, displacement of capacity with a heat rate of 11,000 Btu/kWh would be 15 percent of the oil or gas price (approximately $\$0.90/10^6$ Btu). In the longer term with the value of capacity included in the potential premium, the value would increase to approximately $\$1.50/10^6$ Btu over the oil or gas price if \$.07/kWh is the displaced cost of purchased power, 30 percent methanol is used in the overfiring mode, and a 2 percent efficiency gain is achieved.

The restriction at Long Beach was negotiated with a predecessor of the California Coastal Commission and changes would have to be negotiated with that agency. The restriction covers all pollutants and also other considerations such as thermal discharges, so it is not clear that a reduction of air pollutants would be sufficient to lift the restriction. Assuming that the restriction could be lifted and the capacity factor increased to 60 percent, there would probably be little benefit relative to displacing less efficient units because of the relatively high heat rate at Long Beach. Relative to purchasing power at 7¢/kWh, with oil or gas at \$6/MBtu, the premium for methanol would be \$0.40/MBtu.

10. Value of Methanol in NO_x Emission Reduction Strategies

Substitution of methanol for fuels now in use has often been considered as a means to reduce emissions of nitrogen oxides which are a key contributor to photochemical smog in Southern California. Recent establishment of requirements for reducing NO_x emissions from utility boilers permits estimation of the premium that might be paid for methanol as part of a strategy to meet these requirements.

SCE and LADWP are required under terms of an out-of-court settlement of their suit against the state and local regulatory agencies to reduce basin-wide NO_x emissions from boilers according to the schedule shown in Table 9-27. Both utilities believe that implementation of their current resource plans will result in meeting the requirements in Table 9-27 without use of any additional emission control steps. The resource plans call for reduced reliance on in-basin boilers and a shift to nuclear, renewables and out of state coal. If the limits in Table 9-27 are exceeded for three consecutive years (or for 2 two-year periods), the settlement requires that the utility add NO_x emission control equipment to avoid future exceedances.

If the resource plan is not adhered to and heavier reliance is placed on existing plants, the utility would have to take steps to reduce NO_x

Table 9-27. NO_x EMISSION LIMITS FOR GENERATING SYSTEMS LOCATED WITHIN THE JURISDICTION OF THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT AND VENTURA COUNTY AIR POLLUTION CONTROL DISTRICT (*tons/year*)

YEAR	SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT		VENTURA COUNTY AIR POLLUTION CONTROL DISTRICT
	LADWP	SCE	SCE
1982	6,530	21,300	7,580
1983	7,350	19,800	6,940
1984	8,270	18,950	6,510
1985	8,340	18,230	6,510
1986	8,900	14,060	5,150
1987	8,420	12,200	4,650
1988	7,220	12,430	4,330
1989	6,080	12,180	4,250
1990 and beyond	4,200	11,780	4,460

Note: This table is subject to adjustment pursuant to the terms and conditions of the Stipulation and Order for Judgement

SOURCE: Superior Court of the State of California, Stipulation for Order, Case #C323997, March 1982.

emissions either by adding emission controls or shifting to a low emission fuel such as methanol. In such a situation the utility would be willing to pay a premium for methanol equal to the levelized cost for the control equipment avoided. To provide estimates of this premium, three hypothetical cases for SCE (combination of South Coast and Ventura County units) in the late 1980s were analyzed:

Case 1 - The San Onofre nuclear plant is not available.

Case 2 - The costs of geothermal generation are excessive.

Case 3 - No natural gas is available.

In all three cases, the baseline assumption was that the lost generation would be made up by firing oil in existing steam turbine units with addition of emission control equipment (either low-NO_x burners or selective catalytic reduction) to meet the limits in Table 9-27. It was assumed that no additional natural gas would be available in Cases 1 and 2. Costs for low-NO_x burners and selective catalytic reduction (SCR) were taken from a survey of control technology costs (unpublished) which showed a capital cost

of $12/kW for low-$NO_X$ burners (negligible impact on operating costs), and capital and operating costs of $110/kW and 3.3 mils/kWh, respectively, for SCR (all in 1981 dollars). Because the applicability of the low NO_X burners to all of the plants in question could not be confirmed, it was decided to provide estimates for both Options A and B in Table 9-28, although Option B is believed to be the more probable.

Several methanol alternatives were considered including straight methanol firing, dual fueling and repowering (Options C through F in Table 9-28). (Other alternatives, such as gas/oil dual fueling, increasing other renewable sources or increasing purchases, were not considered here.) Option C-1 represents current methanol combustion technology, while Option C-2 represents emission performance that could probably be achieved for methanol by applying combustion modification techniques (e.g., burner stoichiometry variations). The emission factors used for options C through F must be considered as rough estimates at the current state of development.

The premium applicable to using methanol for avoiding the baseline control equipment costs was calculated using the ESEA model to determine the impact of control technology costs on the cost of electricity (see Section D-5). Results for the various cases and alternatives are shown in Table 9-29. For each of the three cases, two subcases are shown: one where the baseline is Option A and one where the baseline is Option B. It can be seen

Table 9-28. NO_X REDUCTION OPTIONS

OPTION	PERCENT OF OIL-FIRED BOILERS APPLICABLE			EMISSION FACTORS* (lb/MWh)
	Case 1	Case 2	Case 3	
A. Selective Catalytic Reduction	65	40	35	0.48
B. Selective Catalytic Reduction	35	0	0	0.48
Low NO_X Burners	65	85	75	1.5
C. Methanol				
1. Current Technology	80	50	40	0.8
2. Advanced Combustion Technology	65	40	35	0.4
D. 30% Methanol Dual Fuel	100	65	55	1.2
E. 15% Methanol Dual Fuel	55	100	85	1.6
Selective Catalytic Reduction	45	0	0	0.48
F. Repowering (see Table 9-22)				
1. Westinghouse--Case 5	NA	100	100	1.7
2. Westinghouse--Case 6	65	40	35	0.4
3. Westinghouse--Case 9	100	60	50	1.1

*Emissions factors for uncontrolled case: oil 2.4 lb/MWh
gas 0.8 lb/MWh

Table 9-29. VALUE OF METHANOL AS ALTERNATIVE TO ADDITION OF NO_X EMISSION CONTROL EQUIPMENT

CASE	1. SAN ONOFRE NOT AVAILABLE		2. GEOTHERMAL GENERATION NOT AVAILABLE		3. NO GAS AVAILABLE	
1990 Steam Turbine Generation (GWH)						
oil	23,400		16,400		19,000	
gas	7,000		7,000		0	
Average emission factor allowable (lb/MWh)	1.06		1.38		1.74	
Premium value of Methanol in place of options A or B (1981 $/MBtu)	A	B	A	B	A	B
OPTION C-1	0.70	0.40	0.70	0.10	0.70	0.10
C-2	0.90	0.50	0.90	0.10	0.80	0.10
D	1.90	1.10	1.90	0.20	1.70	0.20
E	2.10	0	2.30	0.25	2.30	0.30
F-1	NA	NA	.90	0.10	1.00	0.10
F-2	1.00	0.50	.90	0.10	1.10	0.10
F-3	.90	0.60	.90	0.10	1.10	0.10
Methanol use (tons/day)						
OPTION C-1	27,000		11,000		11,000	
C-2	22,000		9,000		10,000	
D	10,000		4,000		5,000	
E	3,000		3,000		3,000	
F-1	NA		8,000		9,000	
F-2	21,000		9,000		9,000	
F-3	18,000		8,000		9,000	

in the table that, if the low NO_X burners are as effective as described in Option B, deviations from the resource plan must be substantial in order to generate a significant premium for methanol. It is also noteworthy that the largest premiums are found in the dual fueling cases, although the quantities of methanol used are relatively small.

11. Financial Factors

Decisions on capital expenditures are generally based on providing the lowest life-cycle electricity costs consistent with the ability of the utility to raise capital. In today's situation, with high interest rates and stocks selling below book value, the investor-owned utilities are under pressure from shareholders to avoid capital-intensive projects. This situation could contribute to heavier reliance on existing steam turbine and combined

cycle units than is reflected in the current resource plan, thus increasing the potential market for methanol.

12. Near-Term Fuel Supply Considerations

The likelihood of near-term use of methanol in California stationary applications will be strongly influenced by the cost and availability of conventional fuels (oil and natural gas) and of other alternate fuels. Natural gas is currently the fuel of choice for southern California utilities and industry because of both price and environmental attributes.

Utilities have the lowest priority for natural gas and industry the next lowest, but projected gas availability has been increasing in recent months and shortages in the next ten years are considered unlikely. Deregulation is widely expected to result in utility gas costs rising to a level similar to that of medium to high sulfur residual oil, and thus lower than the price of low sulfur oil used by California utilities. This is illustrated in Figure 9-10, which shows methanol target prices derived from oil and gas price projections in Reference 24 for two economic scenarios defined in the Summary Report. As defined in Chapter 2, the target price represents the price of methanol, delivered to a coastal or inland distribution center, at which the user would choose methanol over the competing fuel. These target prices take into account modification costs and differences in efficiency and delivery cost, but they do not include premiums for environmental benefits which must be dealt with on a case-by-case basis. The general topic of price and availability of oil and gas is discussed in detail in the Summary Report.

Both SCE and PG&E have historically relied on multi-year oil supply contracts that could hinder a transition to methanol. However, current difficulties with the California Public Utilities Commission over take-or-pay aspects of these contracts and the early termination of two such contracts have introduced a high degree of uncertainty into the future of long-term fuel supply contracts, both for oil and methanol. This action is potentially very harmful for new fuels such as methanol, where potential producers would be reluctant to make investments based on contracts that might not be honored.

Alternative fuels that will compete for the same markets as methanol are discussed in the Summary Report. The most significant possibilities for existing power plants are imported liquified natural gas (LNG) and medium Btu gas (MBG) produced from western U.S. coals. LNG does not appear to be a near-term option because of problems in siting of receiving terminals in southern California and the uncertainties surrounding the long-term availability of conventional gas that make construction of such a facility a doubtful financial venture.

SCE has considered the possibility of supplying its Los Angeles area power plants with MBG produced in the nearby desert and transported by pipeline, but the cost was found to be excessive.

13. Cost and Performance Uncertainty

Since the testing of methanol in utility scale systems has been limited in scope and duration, the utilities are not likely to accept the

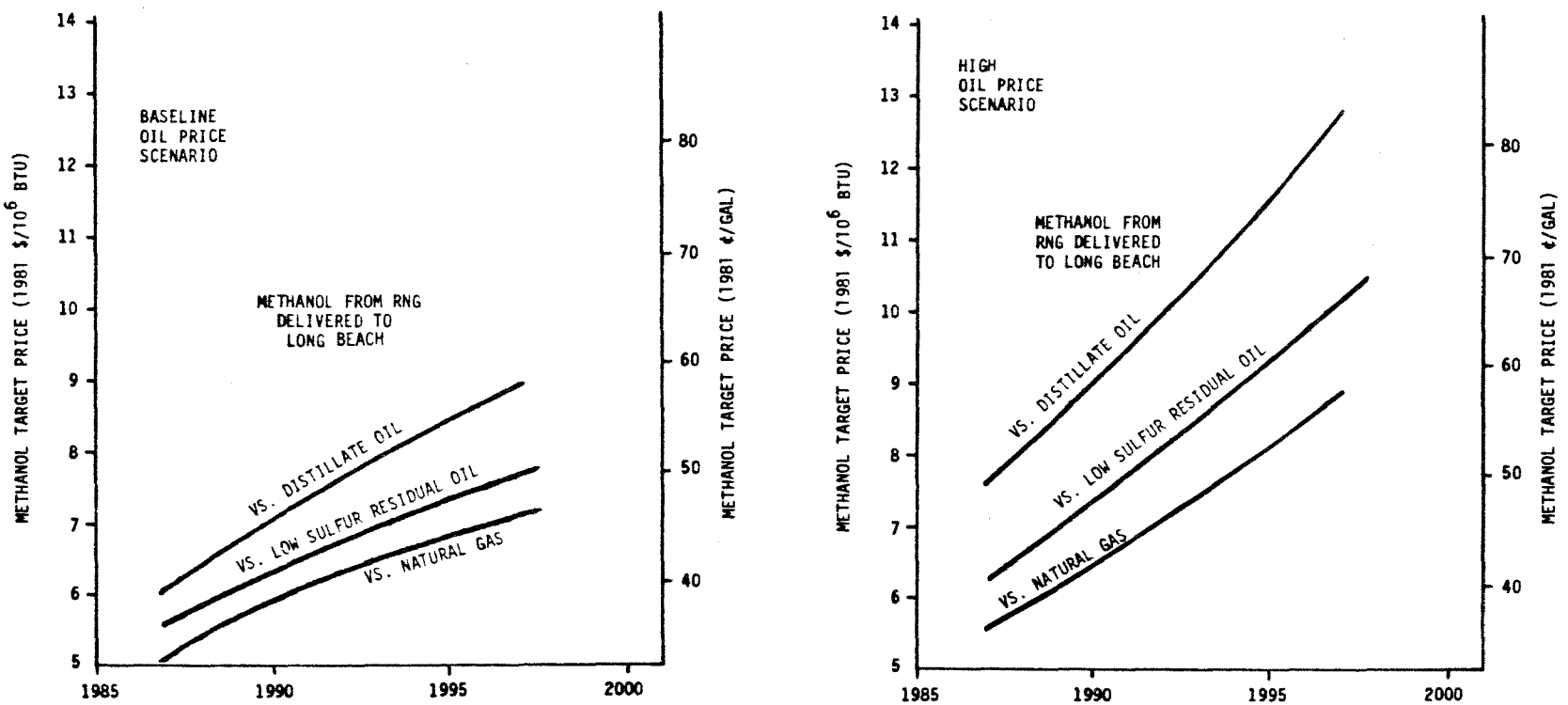


Figure 9-10. METHANOL TARGET PRICES

results at face value or to extrapolate them with a high degree of confidence to larger units or longer time periods. For example, the preliminary heat rate data from the Highgrove test was relatively favorable, but it could be argued that performance in that test would not be typical of larger, more modern boilers with larger radiant heat transfer sections. Thus, in comparing methanol with alternative fuels, it would be appropriate to adjust the methanol cost for the possibility of poorer performance.

Uncertainties of this type are dealt with in a probabilistic manner in utility fuel selection analysis, with weighting factors influenced by the question of who pays for degraded performance. In the heat rate example, if no problem was anticipated in pass-through of higher fuel costs related to higher than expected heat rates, this uncertainty would not be a major factor in the analysis.

Some of the other uncertainties to be considered are related to:

(1) Escalation of methanol production costs.

(2) Costs of modifications.

(3) Costs related to permit delays.

(4) Costs resulting from derating.

(5) Maintenance costs.

(6) Escalation of costs of alternative fuels.

(7) Changes in PUC policy.

(8) Changes in environmental requirements.

14. Vulnerability to Supply Cutoff

In the early stages of the transition to large-scale methanol use, it is envisioned that the methanol would come from a small number of large production facilities, each having its output committed to large users. An interruption of the supply from one of these facilities could not be easily made up. Even in the longer term, when large supplies of methanol are presumed to be available, the utilities have expressed concern that in the event of an oil supply disruption, government authorities would divert methanol to the transportation sector. These considerations would weigh against methanol in utility fuel selection analysis.

On the other hand, long-term contracts for methanol from domestic resources could protect the utilities against the large jumps in cost that have been associated with the international oil supply disruptions of the 1970's. However, changes in PUC policy would be required before any substantial premium could be paid for this protection.

E. POTENTIAL ROLES FOR METHANOL IN STATIONARY APPLICATIONS

The following roles for methanol in the utility sector have been suggested during the course of the California Methanol Assessment:

(1) In new baseload facilities.

(2) In new peaking units: combustion turbines or fuel cells.

(3) In existing units repowered by addition of front end combustion turbines.

(4) As a substitute for oil and gas in existing steam turbines, combustion turbines and combined cycle units.

The first two are long-term roles, while items (3) and (4) are part of the transition question since they apply to units having at most 20-30 years of useful life remaining.

1. Long-Term Roles

A few years ago, there was a great deal of California interest in construction of oil-fired combined cycle baseload units that could be switched to coal-based synfuels as they become available. While all plans for new baseload capacity have been eroding as a result of lower demand projections, the interest in combined cycle units has largely evaporated. This is apparently due to increased confidence in being able to site coal-fired baseload units in or near the state and to a general slowdown of the synfuels thrust. Availability of a secure, inexpensive methanol supply could contribute to a revival of interest in liquid fueled combined cycle units, but the time frame appears to be the mid-1990's. It appears unlikely that life cycle costs for a methanol-from-coal combined cycle system would ever be competitive with direct combustion of the coal or an integrated coal gasification combined cycle system. One option that might be competitive, however, would be a combined cycle using methanol produced using a low opportunity cost gas source.

New peaking units would be a more near-term market for methanol, but the size of this market (a small portion of the distillate oil projections in Table 9-2) is rather small. Methanol-based fuel cell systems could also capture a portion of the intermediate load fuel demand now supplied by oil and gas, but the economics of such systems are not well defined.

2. Utility Transition Roles

This section examines potential electric utility roles for methanol in the next twenty years. These roles relate almost entirely to existing boilers and turbines (although new fuel cells are a possibility).

a. The Current Situation. The key facets of the environment in which utilities currently make fuel selection decisions are summarized here to provide a context for evaluation of potential near-term methanol roles.

(1) There is strong pressure on the utilities and the PUC to hold rates down, leading to emphasis on very near-term rate impact aspects of utility decisions.

(2) Natural gas is available in large quantities and will apparently continue to be beyond 1990, at a price competitive with residual oil.

(3) Methanol is perceived by the potential users to be very expensive and unlikely to be competitive with gas or oil (on a dollars per Btu basis) for the next fifteen years. This was confirmed by the present study (compare the oil and gas target prices in Figure 9-10 with methanol costs in Chapter 4).

(4) Growth rates continue to be lower than expected, and capacity additions continue to be deferred.

(5) SCE and LADWP have reached an agreement for reducing NO_x emissions which can be met without installation of emission controls if current resource plans which call for decreased reliance on oil and gas are implemented.

This situation is not very promising in terms of near-term methanol use. However, some circumstances have been identified in which substantial quantitites of methanol might be used in the utility sector. These are discussed in the following subsection.

b. Potential Methanol Roles. The utilities are generally concerned that it may be necessary to rely more heavily on existing oil- and gas-fired plants than resource plans currently indicate, and that environmental restrictions will hinder this. Among the potential circumstances cited were:

(1) Delays in licensing and/or construction of nuclear and coal plants.

(2) Renewables not meeting cost and schedule goals.

(3) Reduced gas availability.

(4) Prolonged adverse hydro conditions.

(5) Unexpected increases in demand.

In southern California, the NO_x reduction agreement and potential tighter restrictions on SO_x emissions in the AQMP could substantially increase the costs associated with increased use of oil and gas for in-basin units.

As a result of these considerations, SCE and LADWP have shown continued interest in alternative fuels for their existing boilers and turbines, as evidenced by SCE's test programs and LADWP's recent funding of a study of alternatives. (PG&E appears to have more confidence in their ability to obtain gas and has shown less interest recently in alternatives.) The options that involve methanol are discussed here in the transition context.

(1) Peaking Combustion Turbines. SCE has five large combustion turbines totaling 630 MW and several smaller ones, which are used for peaking and operate at average capacity factors of only 2-3 percent. These burn distillate and gas and would be the first place where methanol would be cost competitive because of improved efficiency. However, the likely usage is quite small, on the order of 200 tons/day. Successful load management programs will probably maintain peaker capacity factors at low levels for the next 10-15 years.

The desire to gain more experience in handling and knowledge of long-term materials impacts could lead to dedication of one large turbine for long-term methanol testing before methanol becomes cost competitive. The impacts of such a test on rates would probably be negligible, but there have been problems with the PUC in the past over similarly "negligible" R&D expenditures.

(2) Existing Combined Cycle Units. SCE has four combined cycle units (two at Long Beach, two at Cool Water) totaling about 1000 MW capacity. These also burn distillate or gas and are likely candidates for methanol in case of reduced gas availability. These units use heat recovery boilers with no supplementary firing. The Long Beach units are good candidates, because they are suppliable by water and currently are restricted to 34 percent capacity factor because of emissions. The substantial NO_x reductions achievable with methanol could lead to relaxation of this restriction, which could result in a moderate premium payable for methanol (see Section D-9).

(3) Restricted Steam Turbines. The two SCE Ormond Beach units (1500 MW) and the LADWP Scattergood 3 units (500 MW) are restricted to operate at less than full load because of NO_x emissions. Use of methanol to eliminate these restrictions could result in substantial premiums for methanol (see Section D-9). Ormond Beach is also a prime location for methanol use because it is supplied by water.

(4) Dual Fueling. As discussed in Section C, small scale tests have indicated that dual fuel firing with methanol can provide disproportionate NO_x reductions, and analytical results have indicated a potential efficiency improvement. The NO_x reduction could lead to premiums for methanol of as much as $2.00/MBtu (in case of major deviations from the resource plan--see Section D-10); while the efficiency improvement (if confirmed) could lead to premiums of up to 20 percent of the price of oil or gas in most boiler applications. For the high oil price scenario in Figure 9-10, such premiums could make methanol competitive with petroleum-based fuels in the early 1990s.

(5) Repowering. Repowering of existing units was also discussed above. Delays in nuclear and coal plants and/or renewables could lead to a need for timely provision of new baseload capacity. Repowering using methanol has the potential to provide inexpensive baseload capacity while contributing to meeting the NO_x reduction requirements (see Tables 9-22 and 9-23). The value of the low emission attribute would be as high as one dollar per million Btu.

(6) Offsets, Bubbles, Etc. Recent EPA regulations have been intended to remove some of the obstacles to the use of offsets and bubbles. While the utilities generally do not have plans for in-basin expansion that would require offsets, there is a strong indication that industrial markets for the offsets could develop within the next decade. On the other hand, many observers are pessimistic about the development of a market in offsets, saying no one who has not totally ruled out the possibility of future expansion will ever sell one.

Use of bubbles by the utilities is more likely, especially in regard to side-by-side use of methanol and higher sulfur oil. The premium for methanol in such an application would be on the order of $.50/MBtu.

3. Maximum Rate of Growth of Utility Methanol Usage

Although all boiler and turbine tests to date have been successful, they have all been short-term tests. Questions regarding corrosion and other long-term effects must still be answered and combustion equipment must be developed. Thus, even if methanol prices were to become strongly competitive with oil and gas in the near future, it is likely that concerns about long-term technical problems, coupled with constraints on capital expenditures and on supplying large quantities of methanol other than by water would result in a gradual phasing-in period. Two schedules for such a phasing-in period have been developed for the Southern California Edison system and are illustrated in Figures 9-11 and 9-12. The first is an agressive development schedule and would only be applied if both SCE and the PUC concluded that methanol use was urgently needed. The second is a more cautious schedule consistent with assumptions that methanol may become cost-competitive in the mid 1990s. It would still require support from the PUC.

Combustion turbines would be the first application in the cautious schedule because of the relative ease of conversion and the small quantities involved. The Long Beach combined cycle units would probably be the next step, since the quantities are moderate, the units are easily supplied by water, the turbine applications will provide an experience base, and the use of methanol may allow lifting of the air pollution based capacity factor limit. At Long Beach, it is likely that one of the seven turbines would be tested first, with later conversion of the other six. A third major step using the experience with handling large quantities gained at Long Beach would be conversion of one unit at one of the two large steam turbine facilities suppliable by water (Ormond Beach or Mandalay) with Mandalay being the most

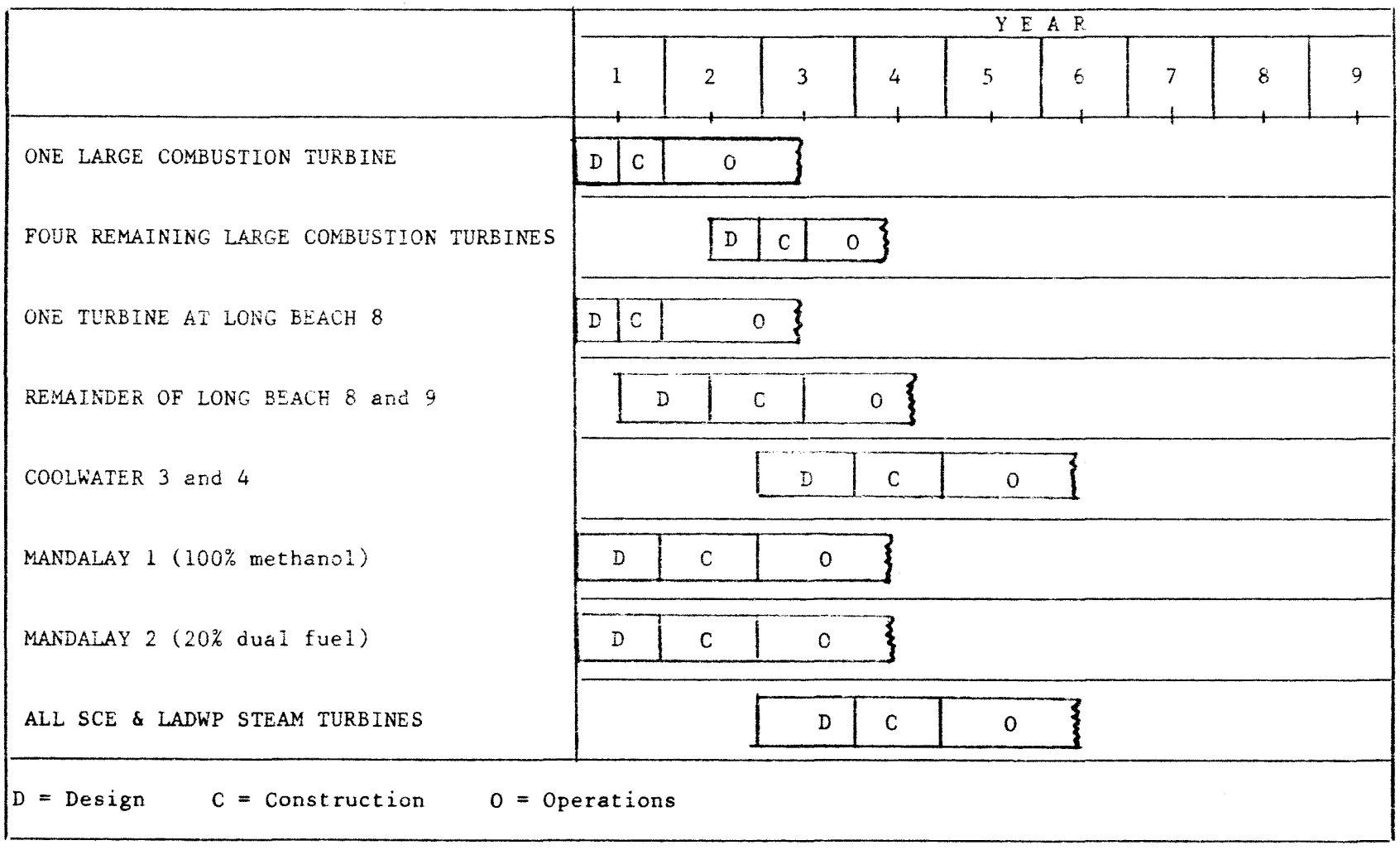


Figure 9-11. PHASING-IN OF UTILITY METHANOL USE--AGGRESSIVE DEVELOPMENT

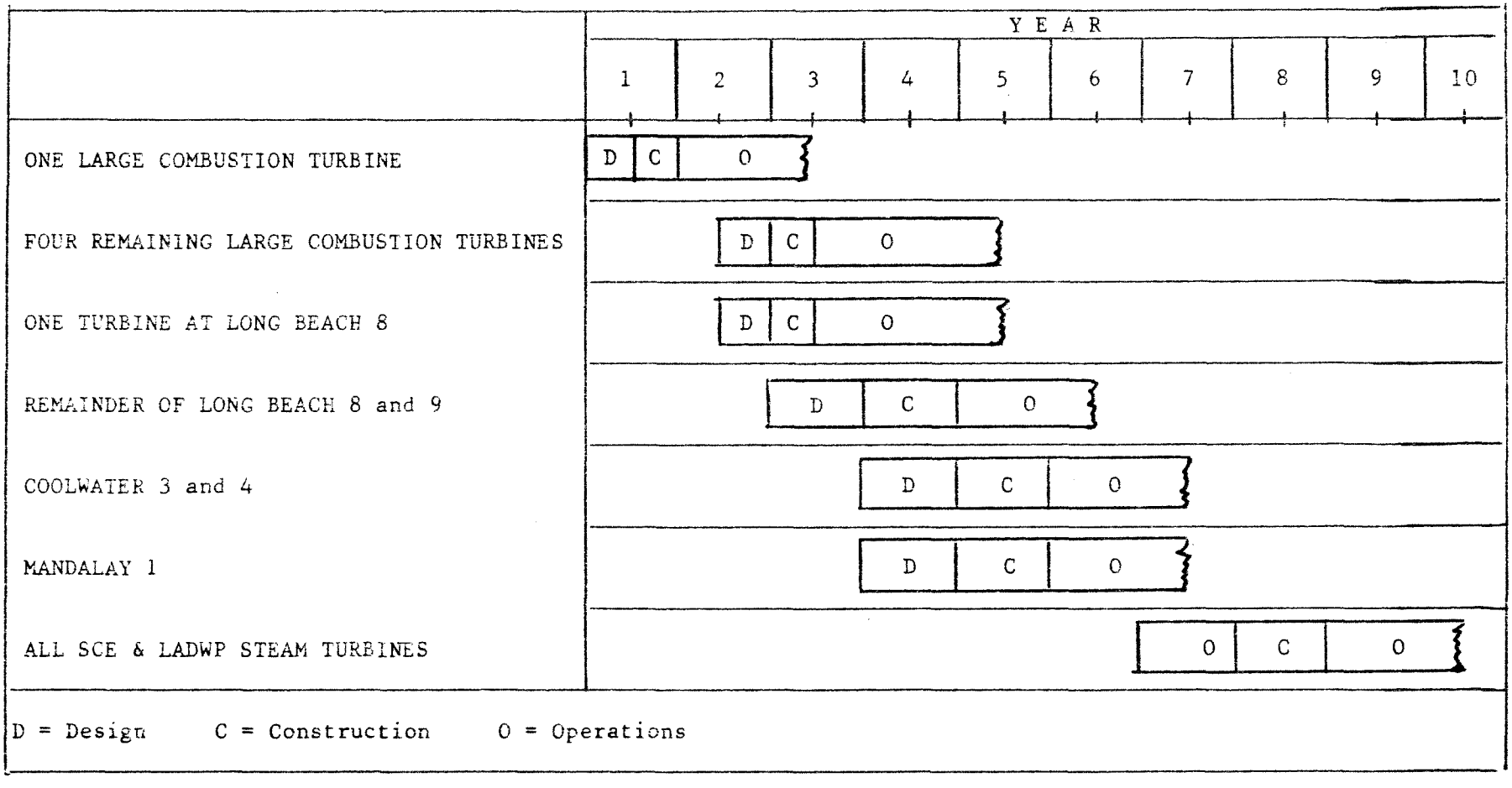


Figure 9-12. PHASING-IN OF UTILITY METHANOL USE--CAUTIOUS DEVELOPMENT

likely because it is smaller. Conversion of the Coolwater combined cycle units could also follow a successful demonstration at Long Beach, while conversion of other large steam turbine facilities could follow a period of successful operation at Mandalay. In the aggressive development case, it is assumed that the combustion turbine, combined cycle and steam turbine steps could be started at once, based on the successful tests at Ellwood and Highgrove.

For each step in the cautious development case, it is assumed that a one-year period of successful operation is required prior to commitment to major modifications for the next phase. For the agressive schedule, this is shortened to six months. In the event of a major disruption of oil and gas supplies, this schedule could be further compressed. In lieu of such a disruption, Figure 9-11 probably represents the most rapid possible build-up for methanol use by the utility sector.

Figure 9-13 shows the methanol quantities associated with the schedules in Figures 9-11 and 9-12. Although the conversion would probably be designed to permit an easy return to oil or gas, it is assumed that all converted units will continue to use methanol. Capacity factors for combustion turbines (3%) and steam turbines (40-50%) were taken from Reference 25. For the Long Beach combined cycle units, it was assumed that the current air pollution based limit of 34 percent would be waived and a 50-percent factor was used. Low NO_x dispatching procedures could lead to higher capacity factors for methanol-fired intermediate load units--possibly as high as 70 percent.

Modern LADWP steam turbine units (Haynes and Scattergood) are also included in the last step of Figure 9-13, since conditions (price, air quality regulations) that would induce SCE to use methanol in their large boilers would probably do the same for LADWP. PG&E is not included because of their long-term gas supply arrangements. Including PG&E's modern steam turbine units at 50 percent capacity factor would add another 23,000 tons/day to the last step in Figure 9-13.

To put these quantities in perspective, it should be recalled that current United States production of methanol is 16,000 tons/day, with a projected increase to 19,000 by 1987. Thus, even an intermediate step such as complete conversion of Long Beach 8 and 9 (3,400 tons/day) would require substantial new sources of methanol.

4. Utility Methanol Demand Curves

Demand curves for methanol for the utility sector during the transition phase are presented in Figures 9-14 through 9-23. These curves were prepared as follows:

(1) All of the modern boilers and combined cycle units indicated in Table 9-3 were assumed to remain in service throughout the transition period. All of the older units were assumed to be retired. Capacity factors were based on Tables 9-4 and 9-5 but were increased in some cases on the assumption that availability of competitively priced methanol would increase

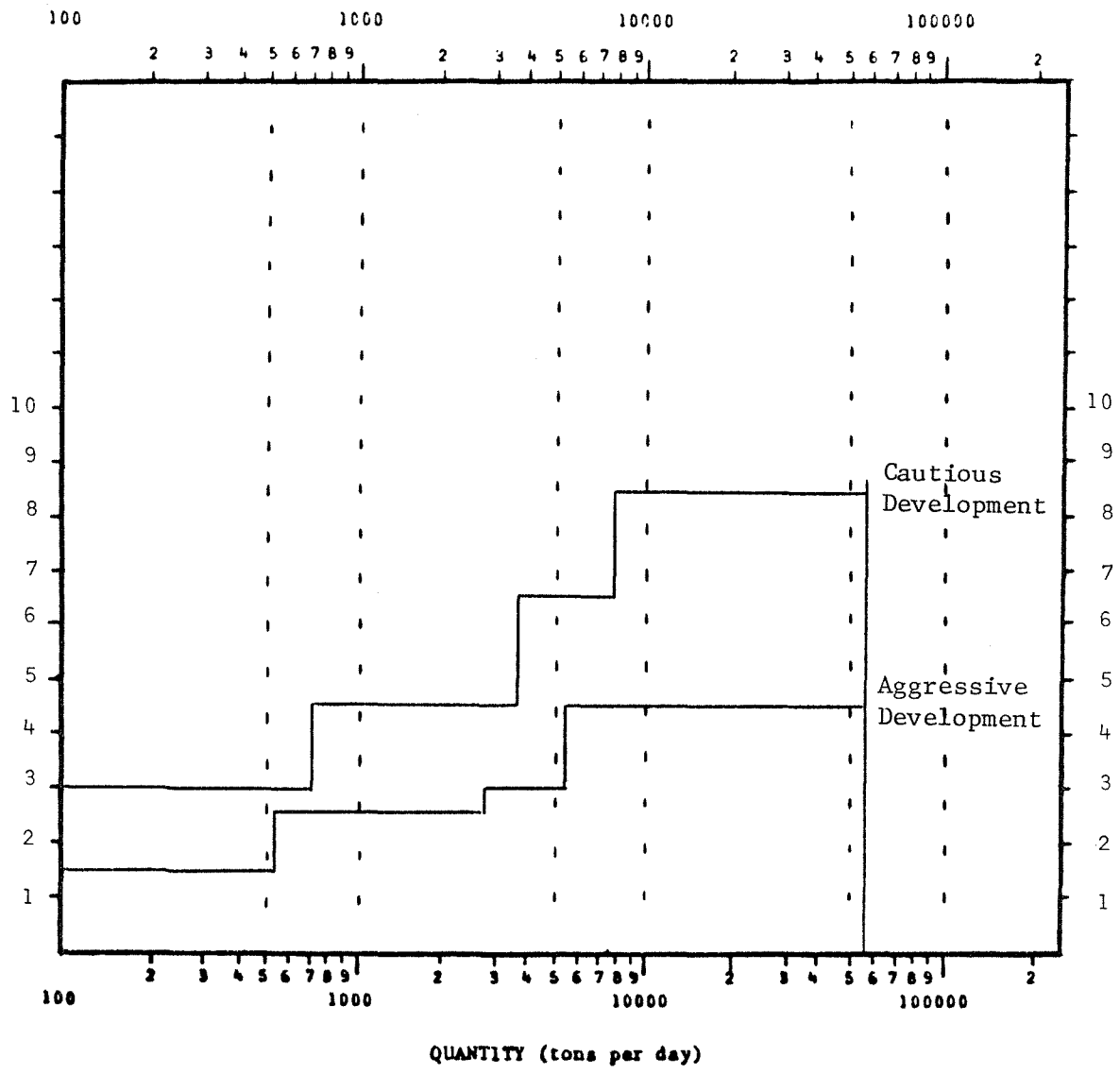
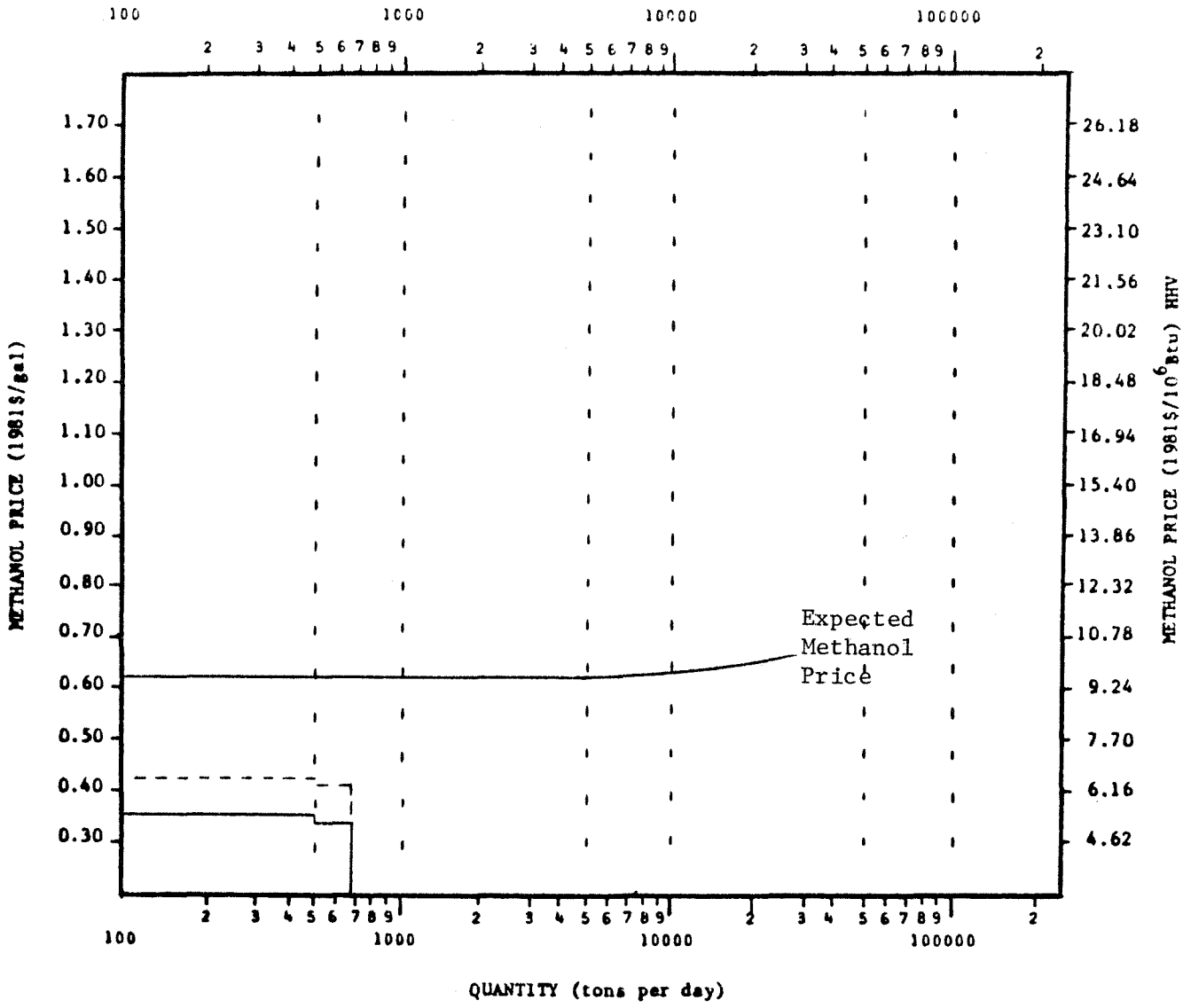


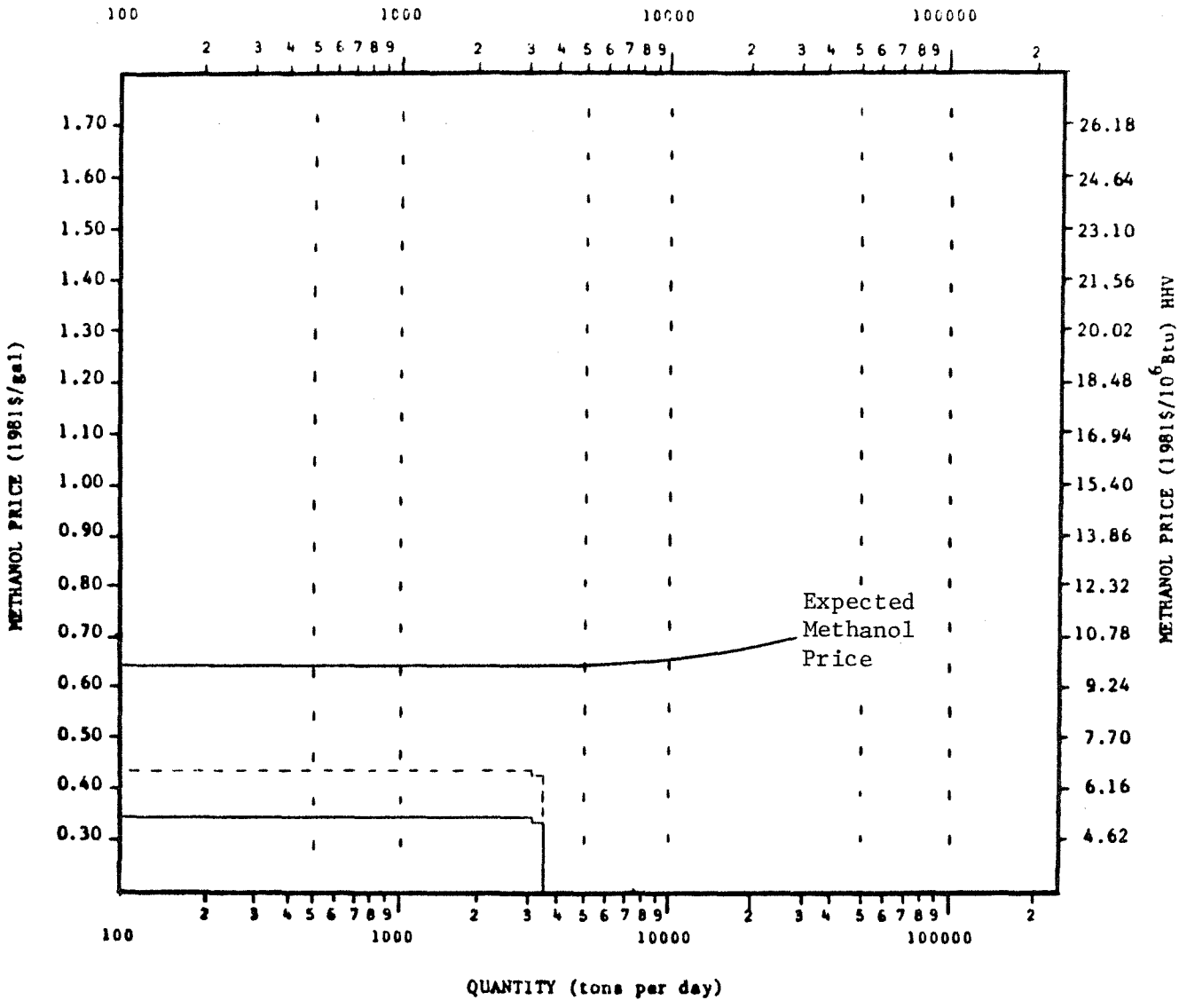
Figure 9-13. MAXIMUM METHANOL USE DURING PHASING-IN PERIOD



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

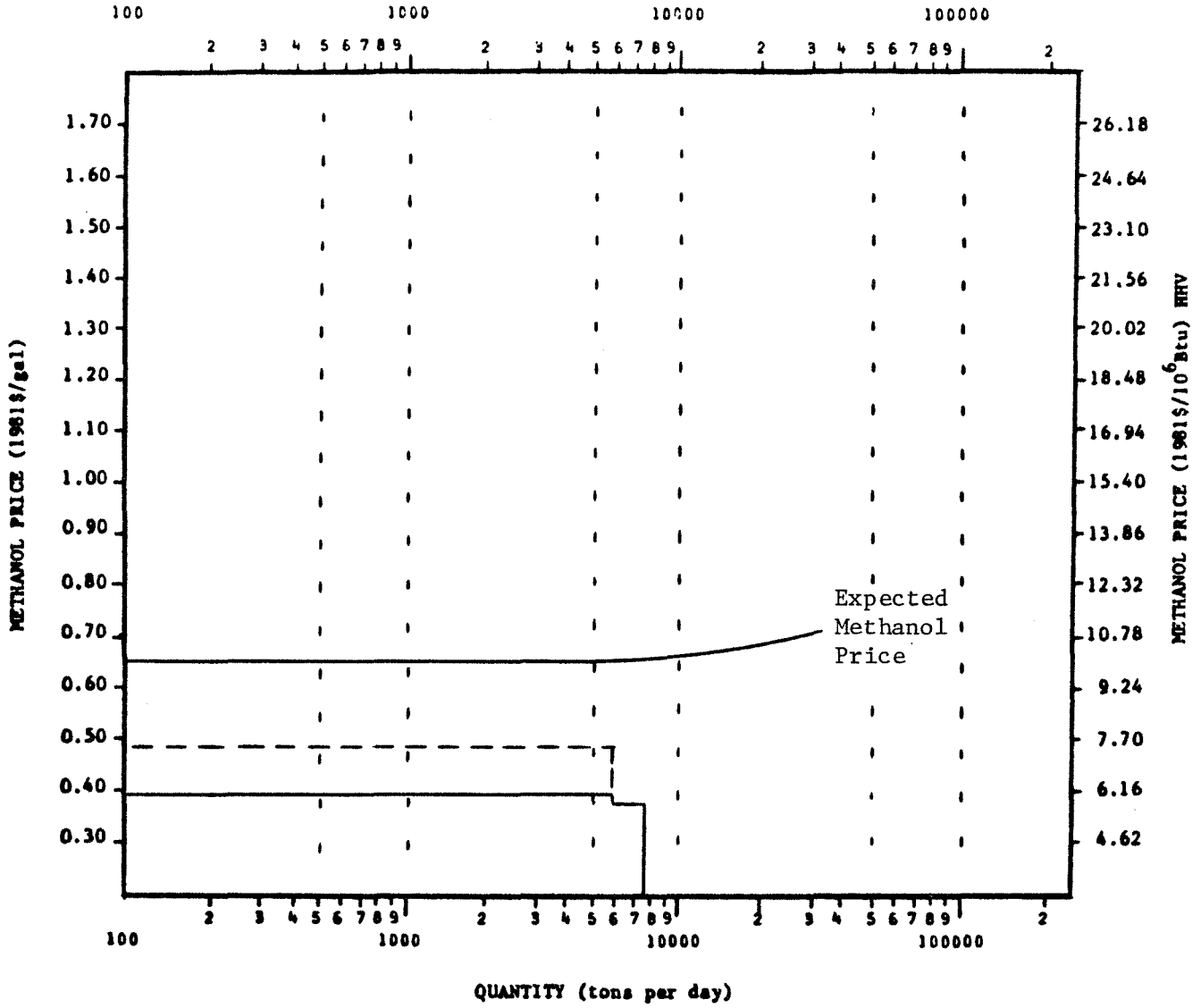
Figure 9-14. 1986 BASELINE SCENARIO METHANOL DEMAND IN UTILITIES



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

Figure 9-15. 1987 BASELINE SCENARIO METHANOL DEMAND IN UTILITIES



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

Figure 9-16. 1989 BASELINE SCENARIO METHANOL DEMAND IN UTILITIES

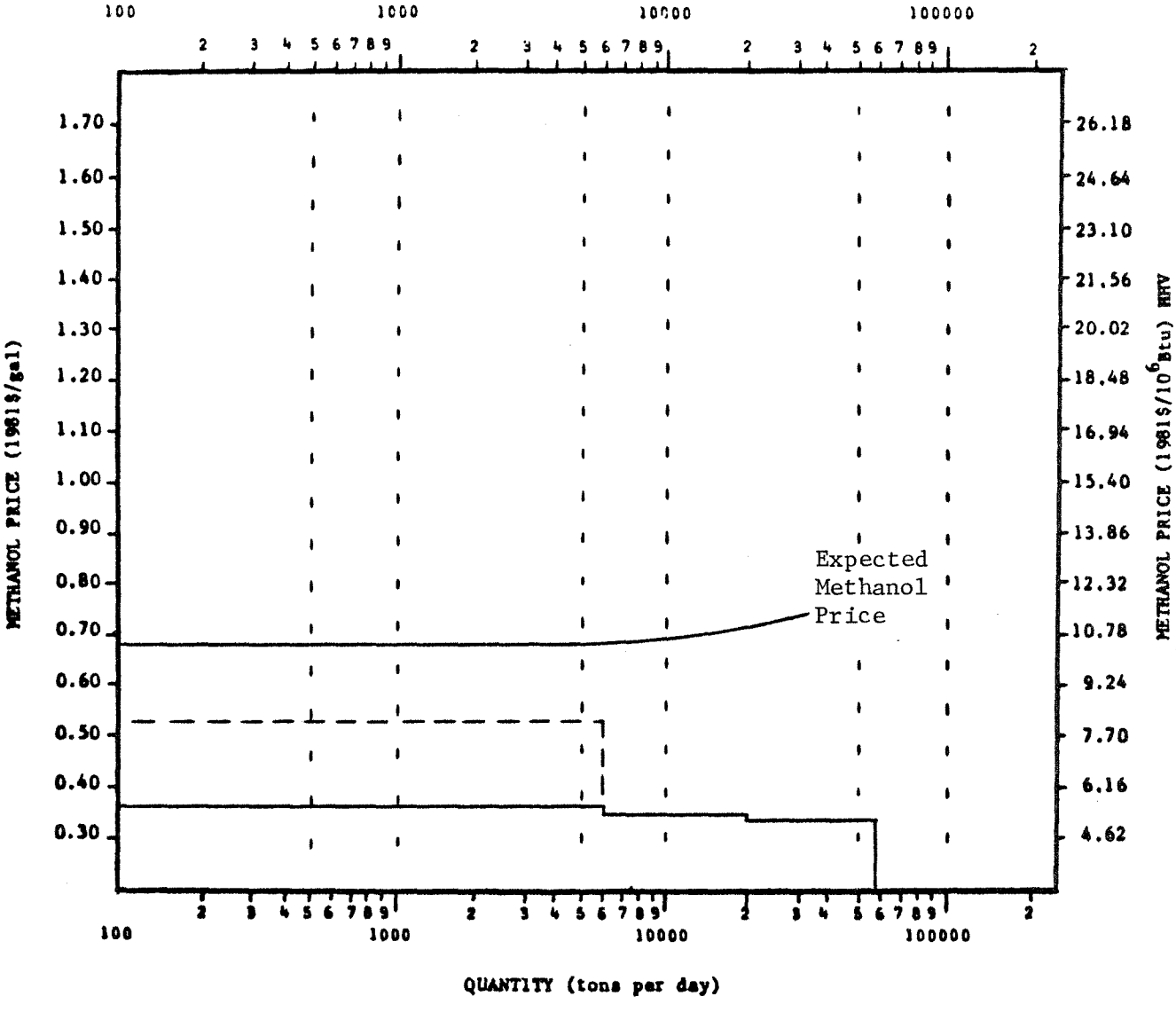
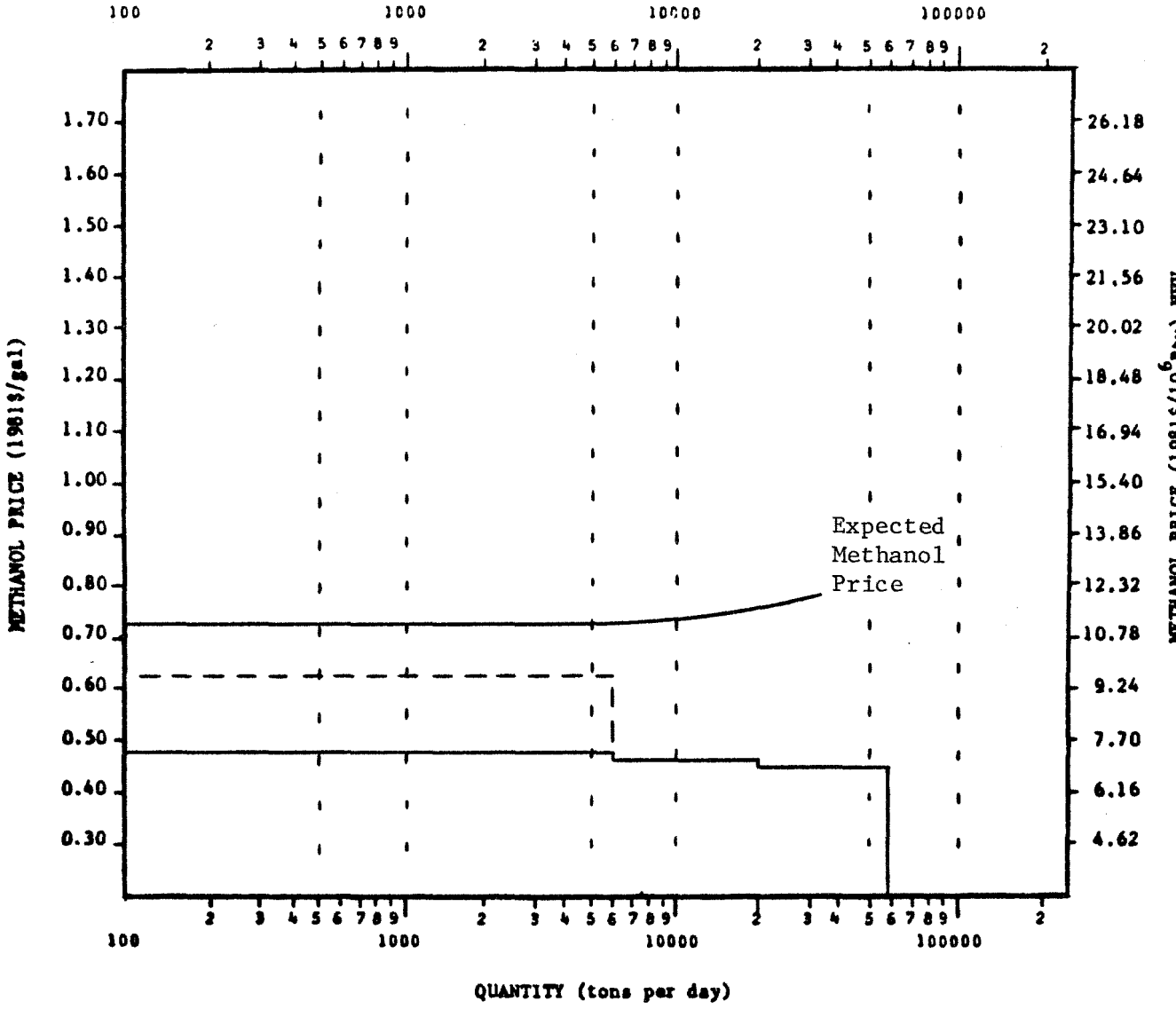


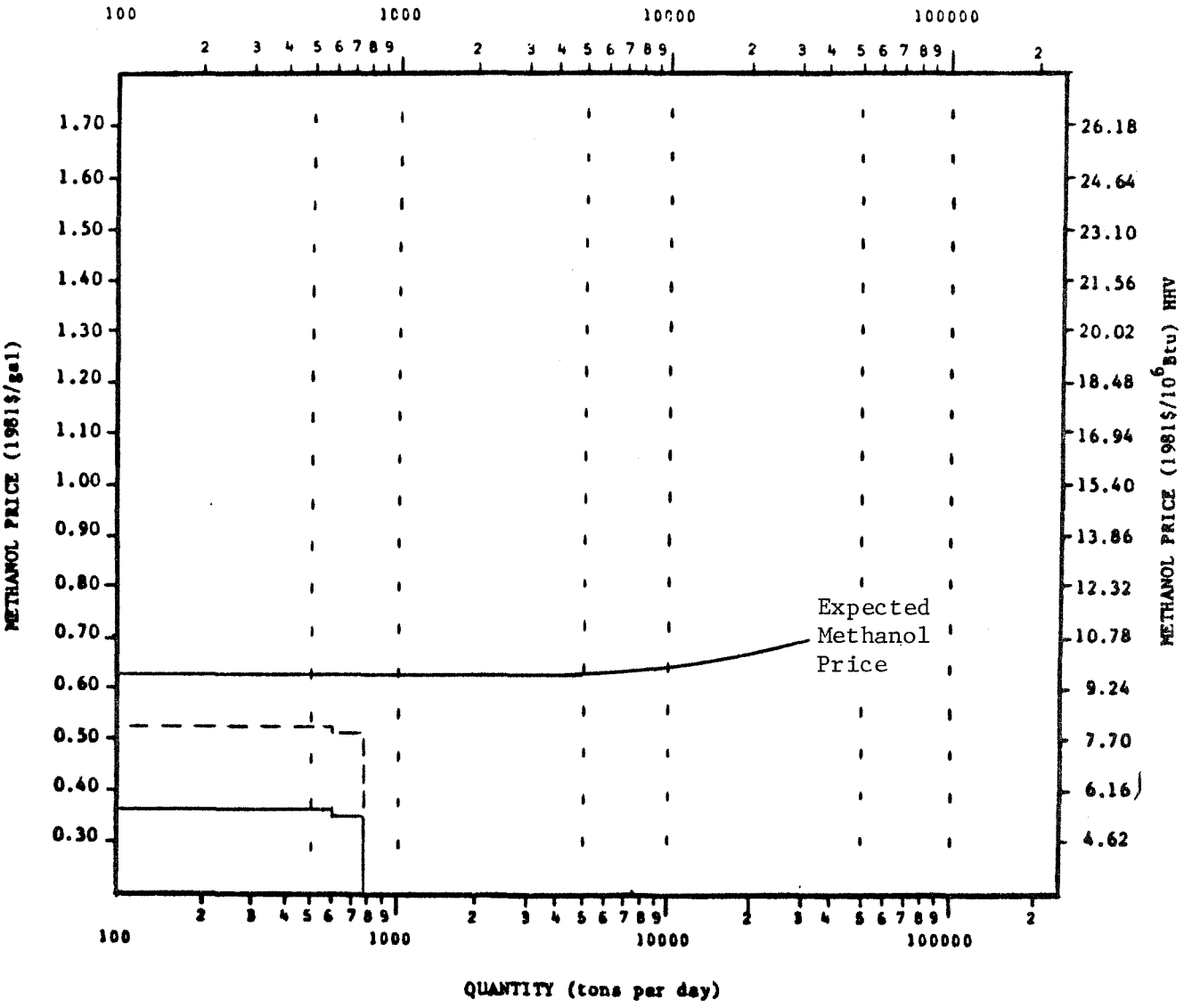
Figure 9-17. 1992 BASELINE SCENARIO METHANOL DEMAND IN UTILITIES



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

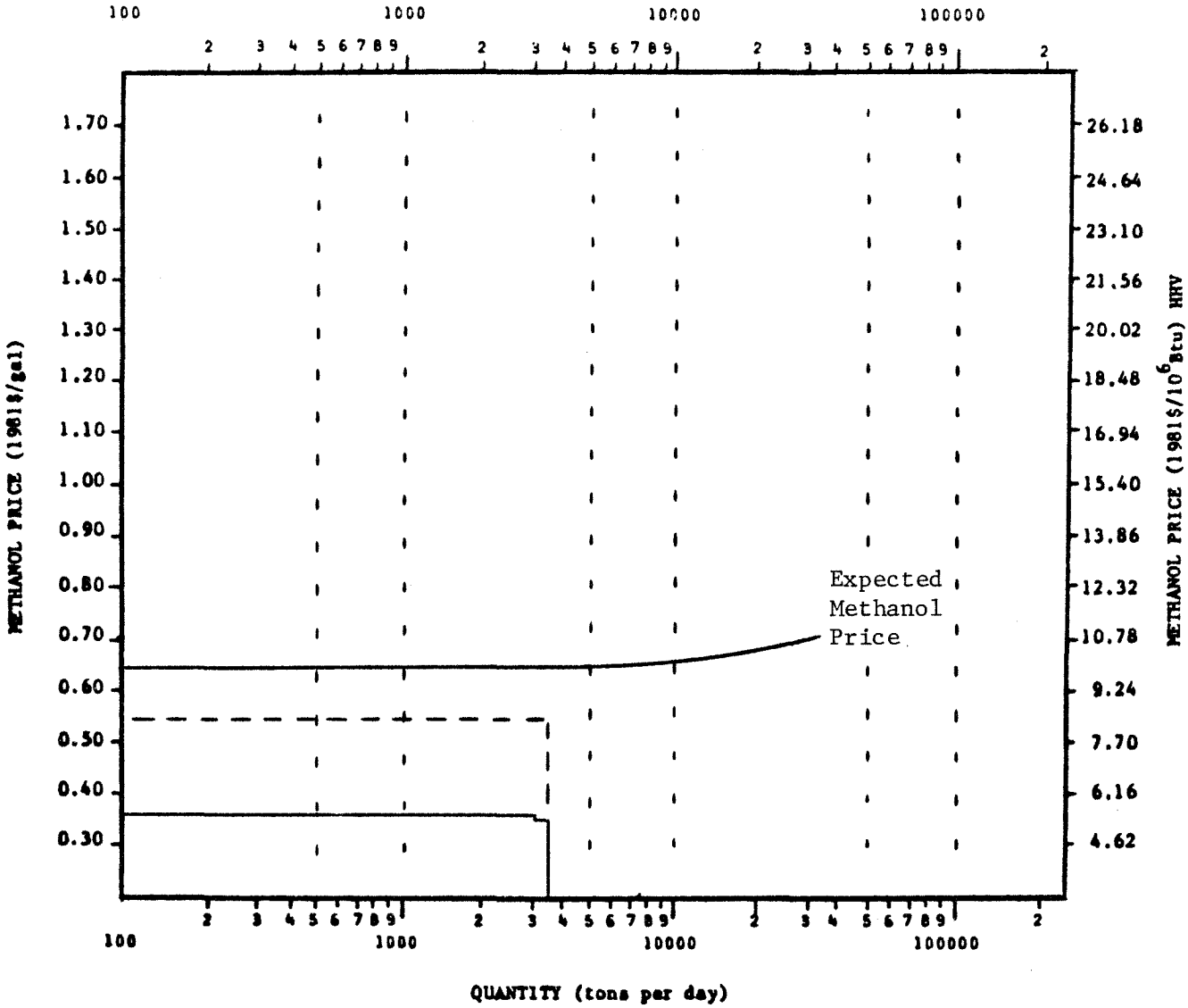
Figure 9-18. 1997 BASELINE SCENARIO METHANOL DEMAND IN UTILITIES



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

Figure 9-19. 1986 HIGH OIL PRICE SCENARIO METHANOL DEMAND IN UTILITIES



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

Figure 9-20. 1987 HIGH OIL PRICE SCENARIO METHANOL DEMAND IN UTILITIES

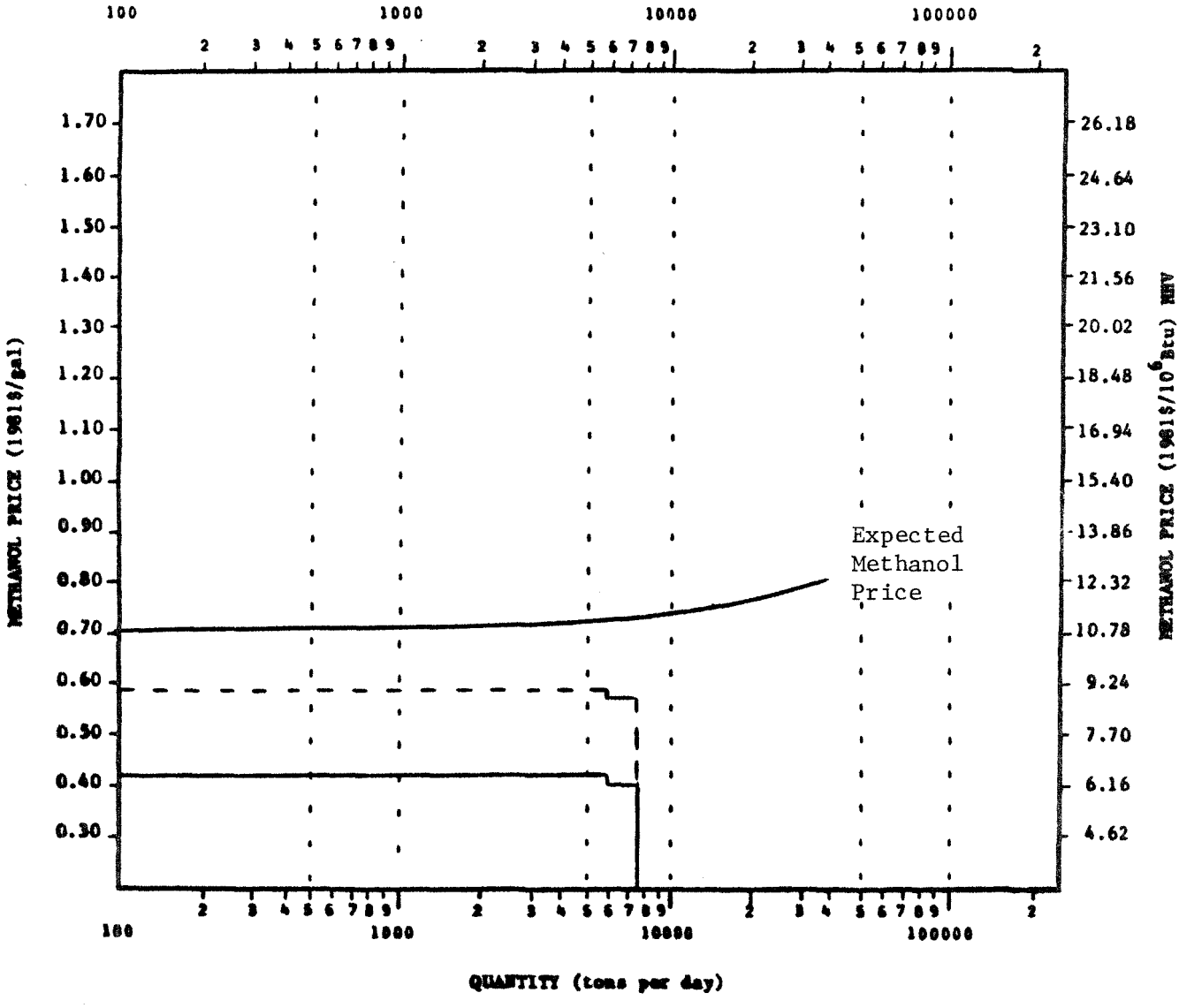
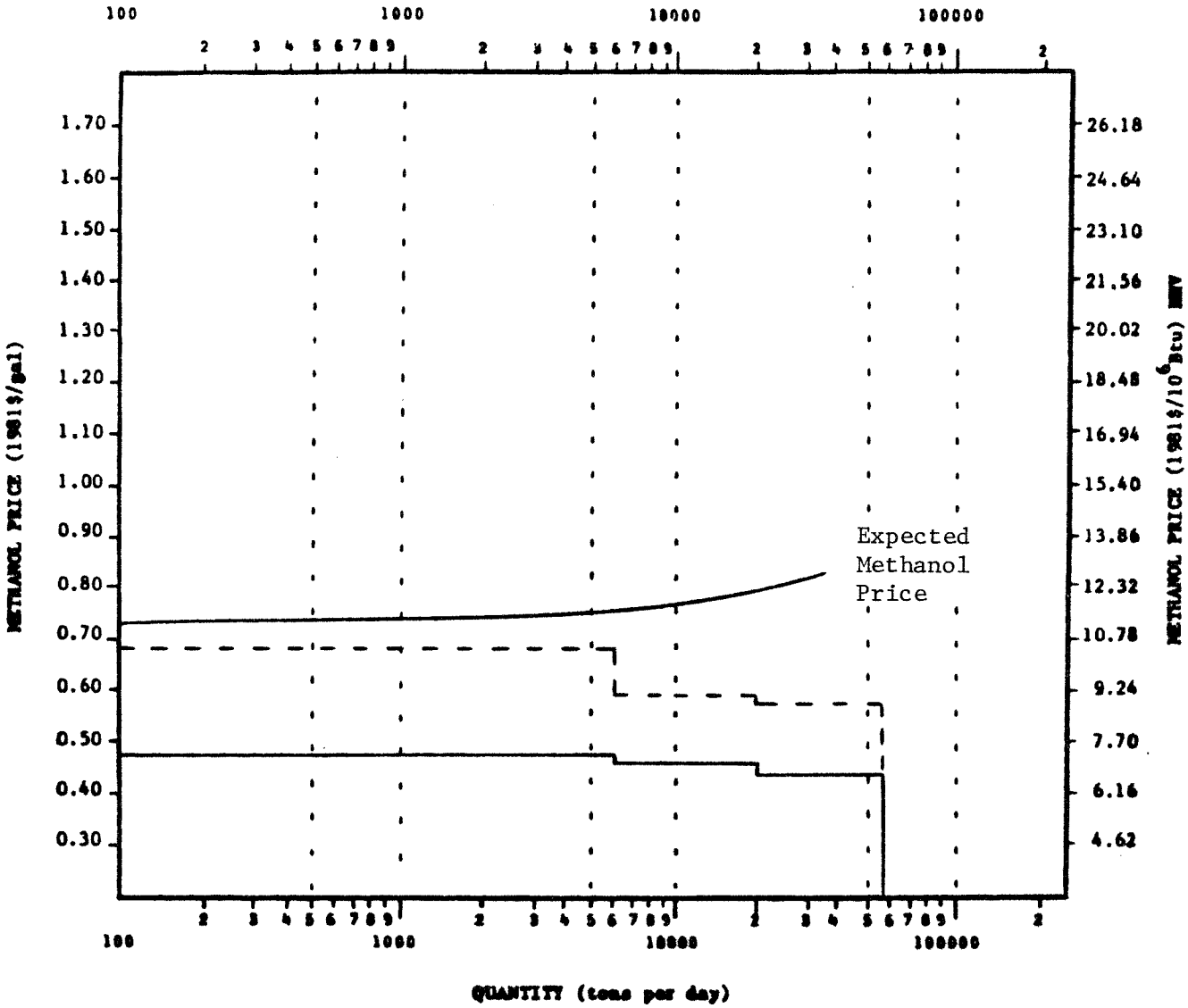


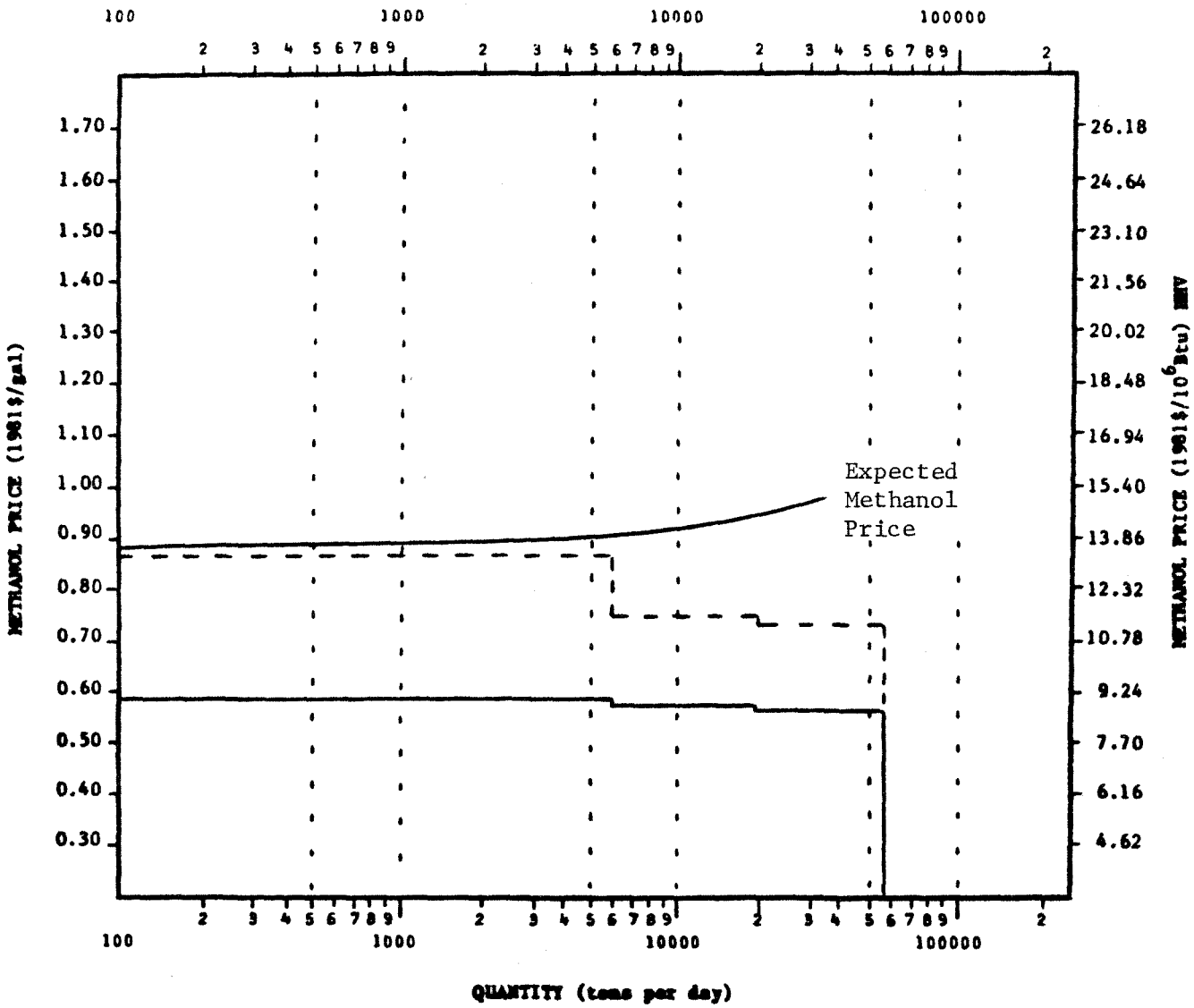
Figure 9-21. 1989 HIGH OIL PRICE SCENARIO METHANOL DEMAND IN UTILITIES



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

Figure 9-22. 1992 HIGH OIL PRICE SCENARIO METHANOL DEMAND IN UTILITIES



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

Figure 9-23. 1997 HIGH OIL PRICE SCENARIO METHANOL DEMAND IN UTILITIES

the reliance on existing fossil fueled units. Capacity factors for environmentally restricted units were also increased.

(2) The methanol usage growth rates for the cautious development case were used, assuming a 1983 start on the schedule in Figure 9-12.

(3) Costs of competing fuels for both the baseline and high oil price scenarios identified in the Summary Report were used, with adjustments as outlined in Section D above. No adjustments were made for environmental benefits since the most likely value of such benefits is zero. Conditions under which environmental benefits become significant are discussed in Sections D-8, 9, and 10. Premiums payable for methanol under some specific conditions are discussed in those sections, and are compared with the methanol price disadvantage indicated in the demand curves in Figures 9-24, 9-25, and 9-26.

(4) PG&E was not included as a potential methanol user during the transition period because of their focus on natural gas and SNG. Including all of PG&E's modern steam turbine units in the 1997 cases would add 23,000 tons/day to the demand curves.

It should be emphasized that for these demand curves to be realized, it would be necessary that the competitiveness of the methanol price be recognized far enough in advance to initiate the developmental program. Even with a 1983 start, the 1992 curve is probably unrealistic in that it is based on the assumption that once methanol is demonstrated in one large steam turbine, all of the other steam turbines would immediately begin conversion if the methanol price was competitive.

For reference, each figure shows the mid-point of the estimated price range for remote-gas-based methanol delivered to a southern California distribution center (see Chapter 4).

If the efficiency improvement for dual-fuel firing is confirmed, the resulting premium payable for methanol would have a significant impact on the demand curves. Figure 9-27 shows changes to Figure 9-17 corresponding to a 2 percent efficiency improvement for 10 percent methanol.

5. Methanol Demand Curves for the Industrial Sector

The potential industrial market for methanol is assumed to include current industrial fuel use (with some exceptions as discussed in Section B), projected growth in industrial fuel use, and the generation of electricity by industrial cogenerators using gas turbines.

Fuel costs are the same as those used in developing the utility demand curves. It is estimated that 10% of the industrial users do not have access to natural gas. A small fraction of users do not have rail access and would require delivery by truck, thus reducing their breakeven price of methanol by a few cents per gallon.

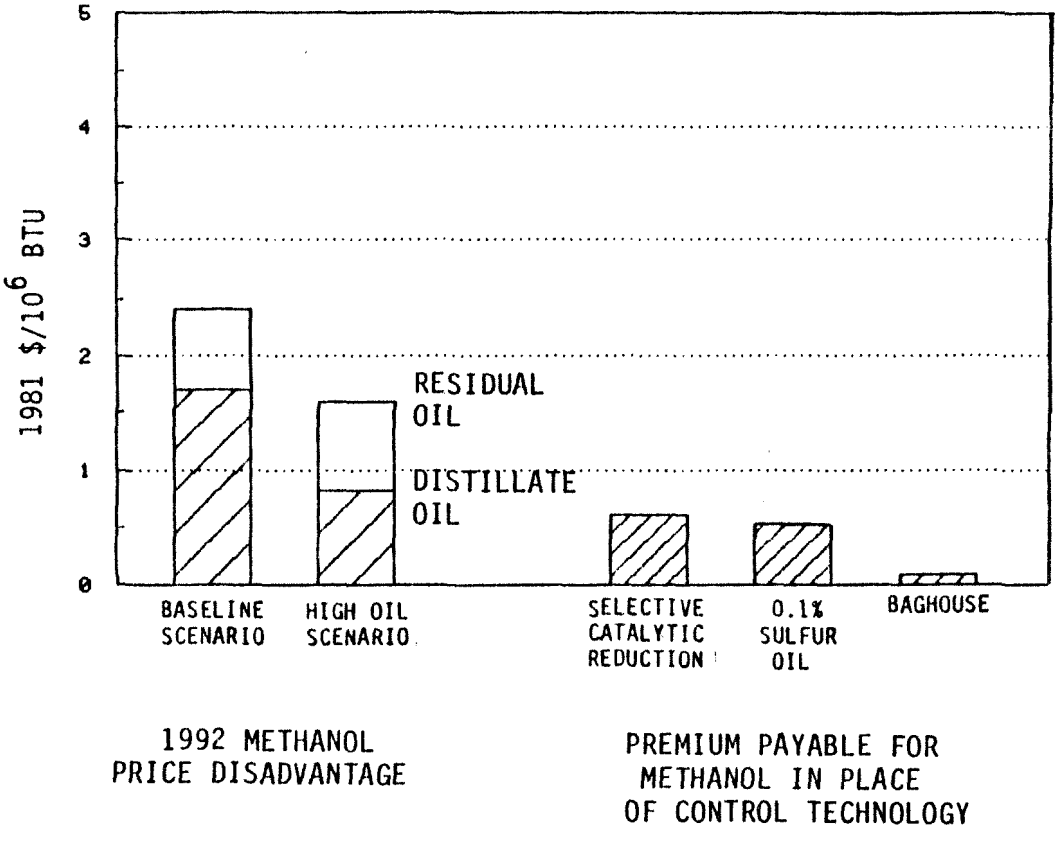


Figure 9-24. POTENTIAL VALUE OF METHANOL IN SIP EMISSIONS REDUCTIONS, OFFSETS, AND BUBBLES

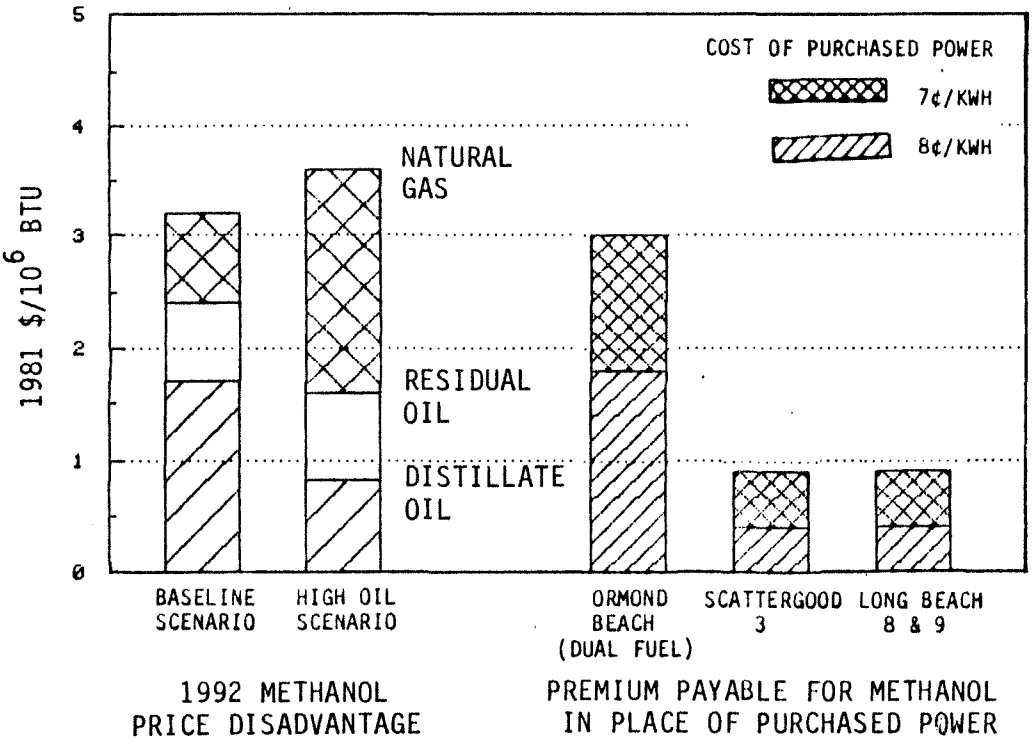


Figure 9-25. POTENTIAL VALUE OF METHANOL IN REMOVING POWER PLANT ENVIRONMENTAL RESTRICTIONS

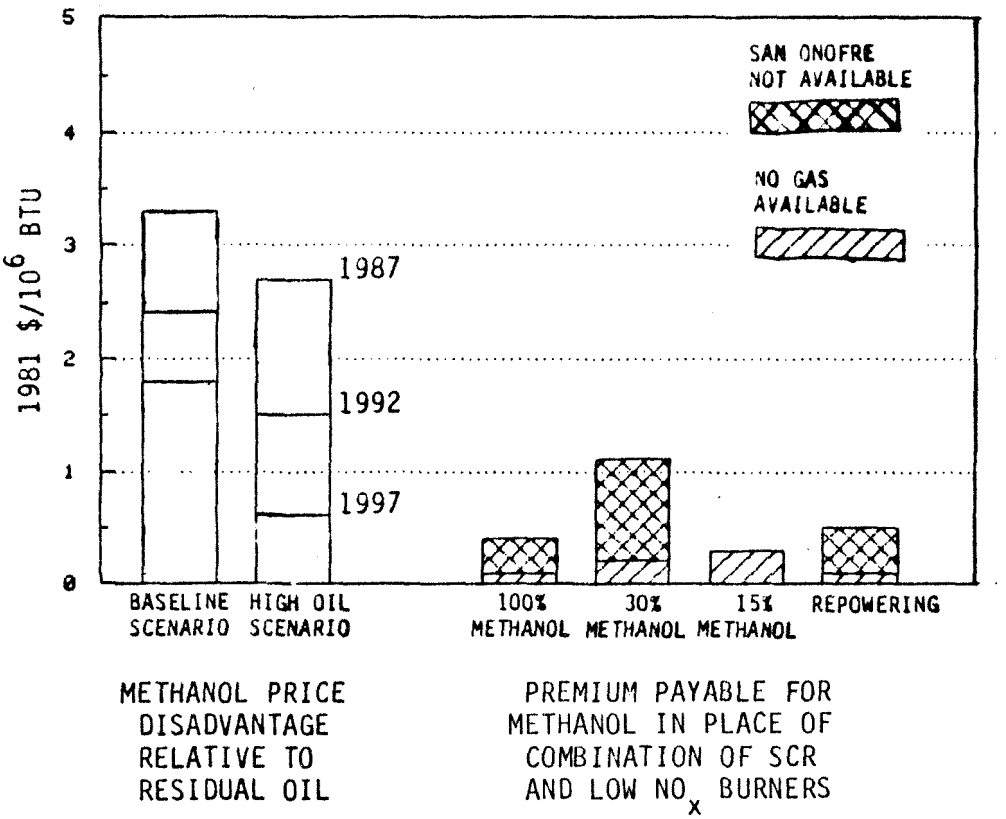
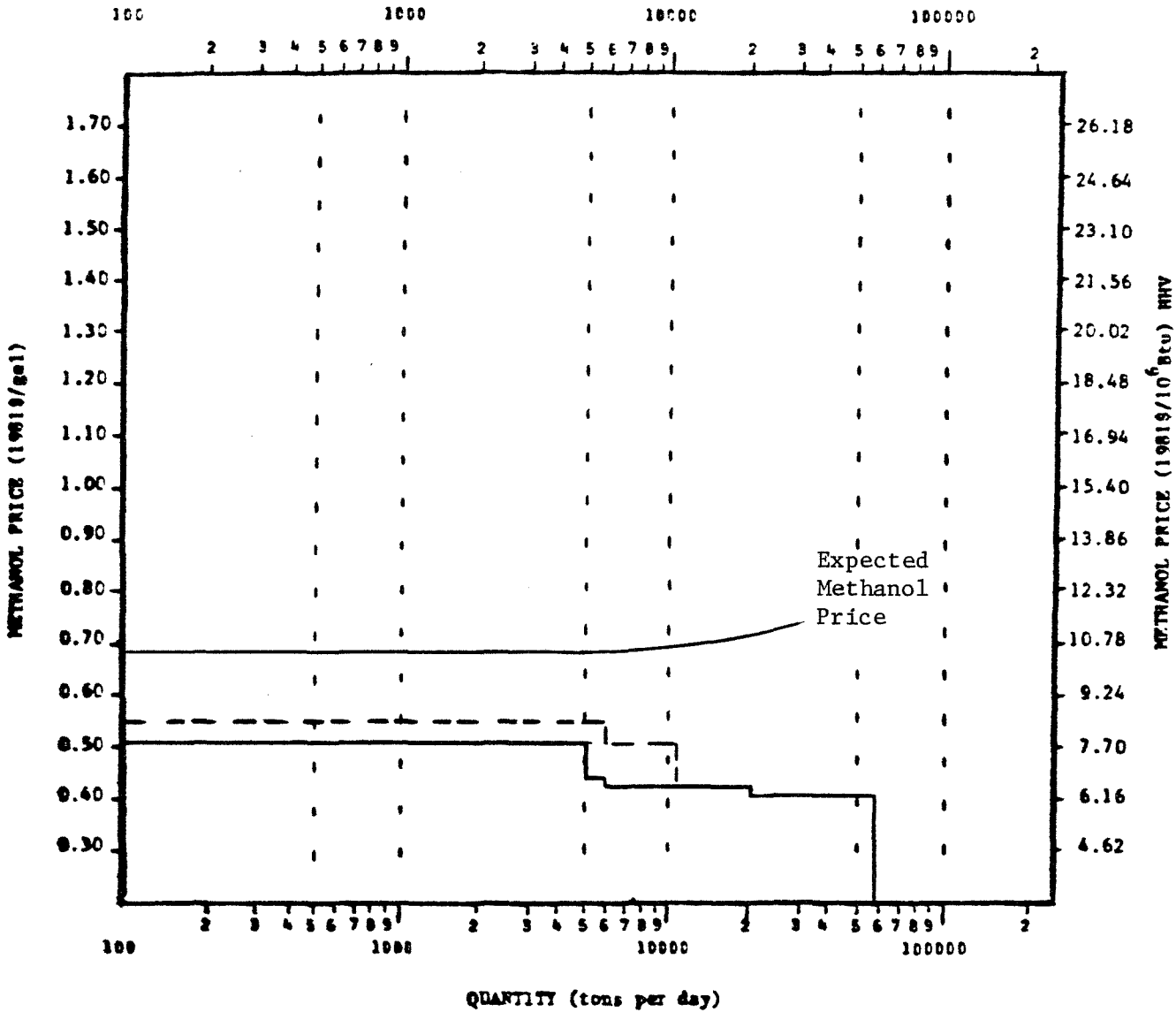


Figure 9-26. POTENTIAL VALUE OF METHANOL IN MEETING NO_x REDUCTION REQUIREMENTS

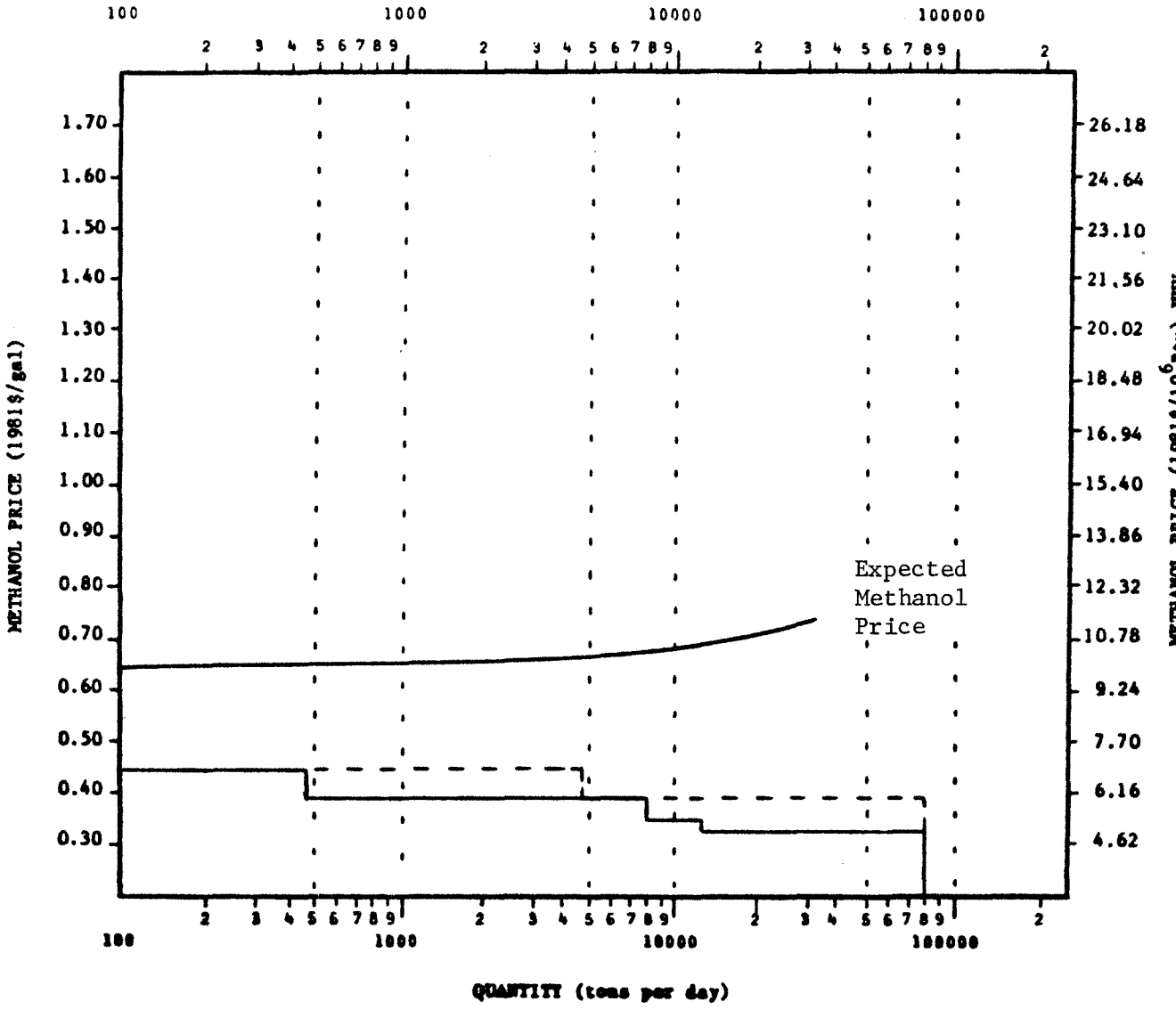


Natural Gas Available ————

Natural Gas Unavailable - - - - -

Figure 9-27. 1992 BASELINE SCENARIO METHANOL DEMAND WITH DUAL-FUEL EFFICIENCY IMPROVEMENT

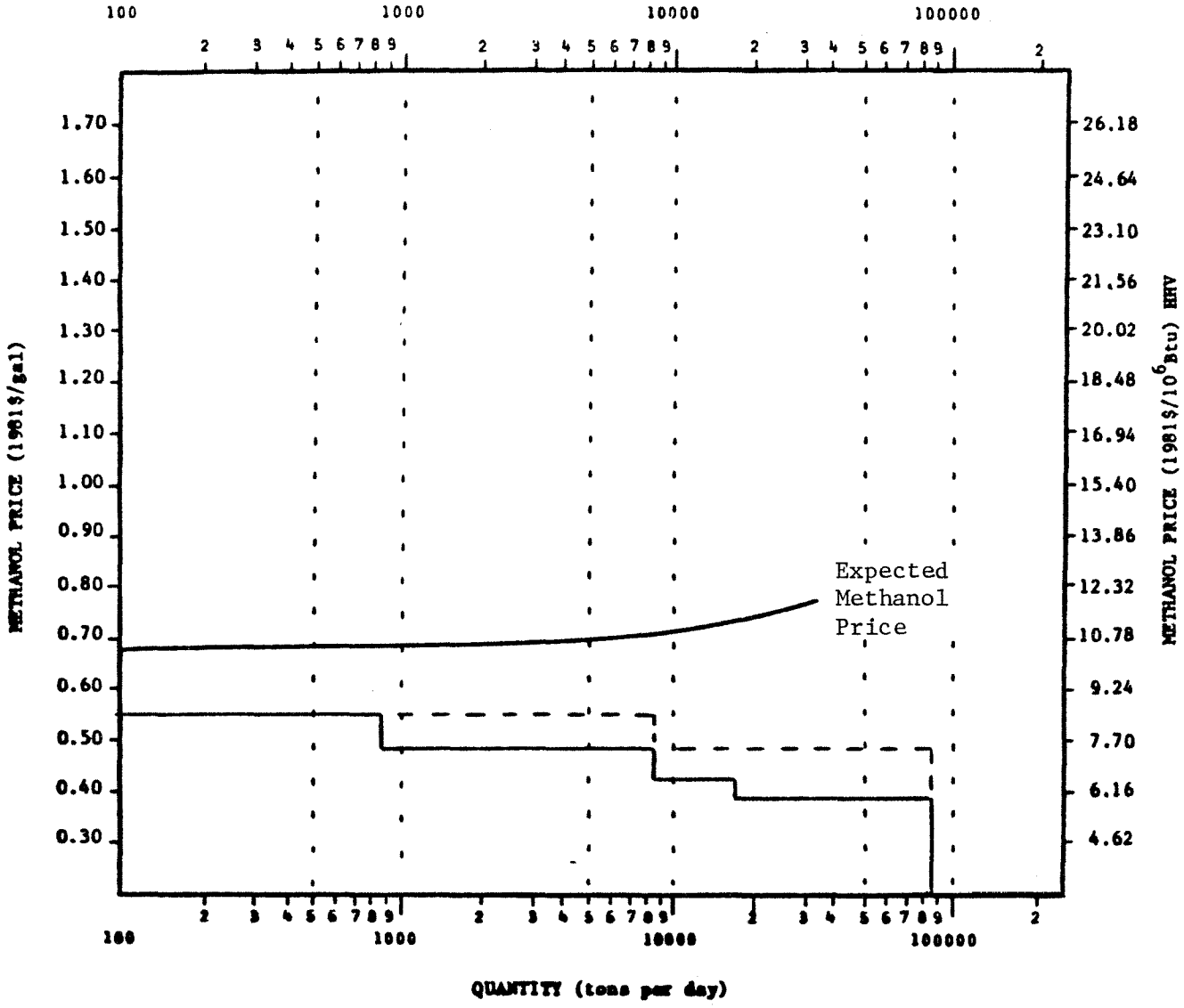
The industrial demand curves are presented in Figures 9-28 through 9-33. The response to a sudden shift in fuel prices would be faster here than in the utility sector, since innovative fuel users, especially those who are energy intensive, would probably consider existing test data adequate to start using methanol. The dual-fueling efficiency improvement would have an impact on these curves similar to that for the utility case.



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

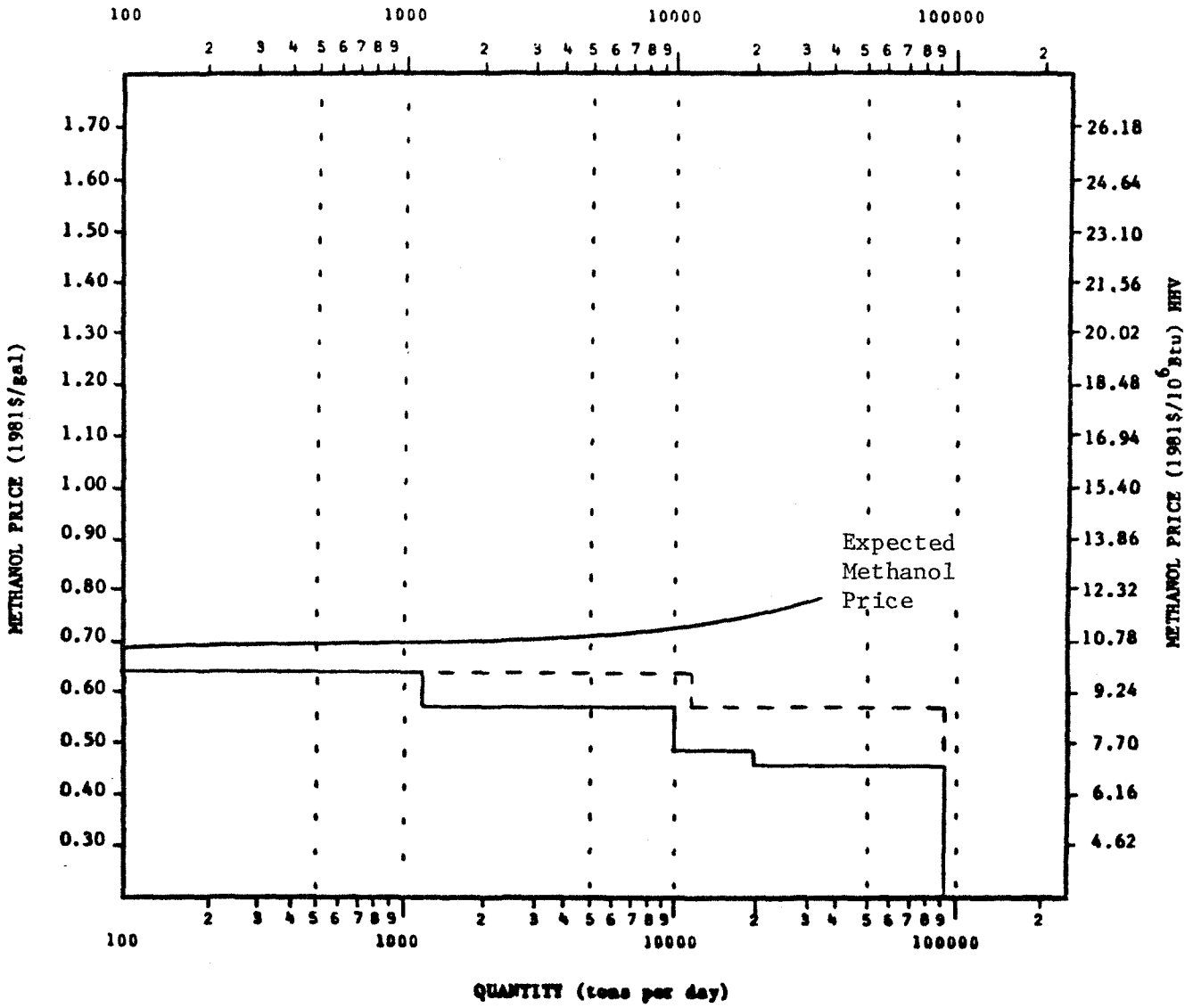
Figure 9-28. 1987 BASELINE SCENARIO INDUSTRIAL METHANOL DEMAND



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

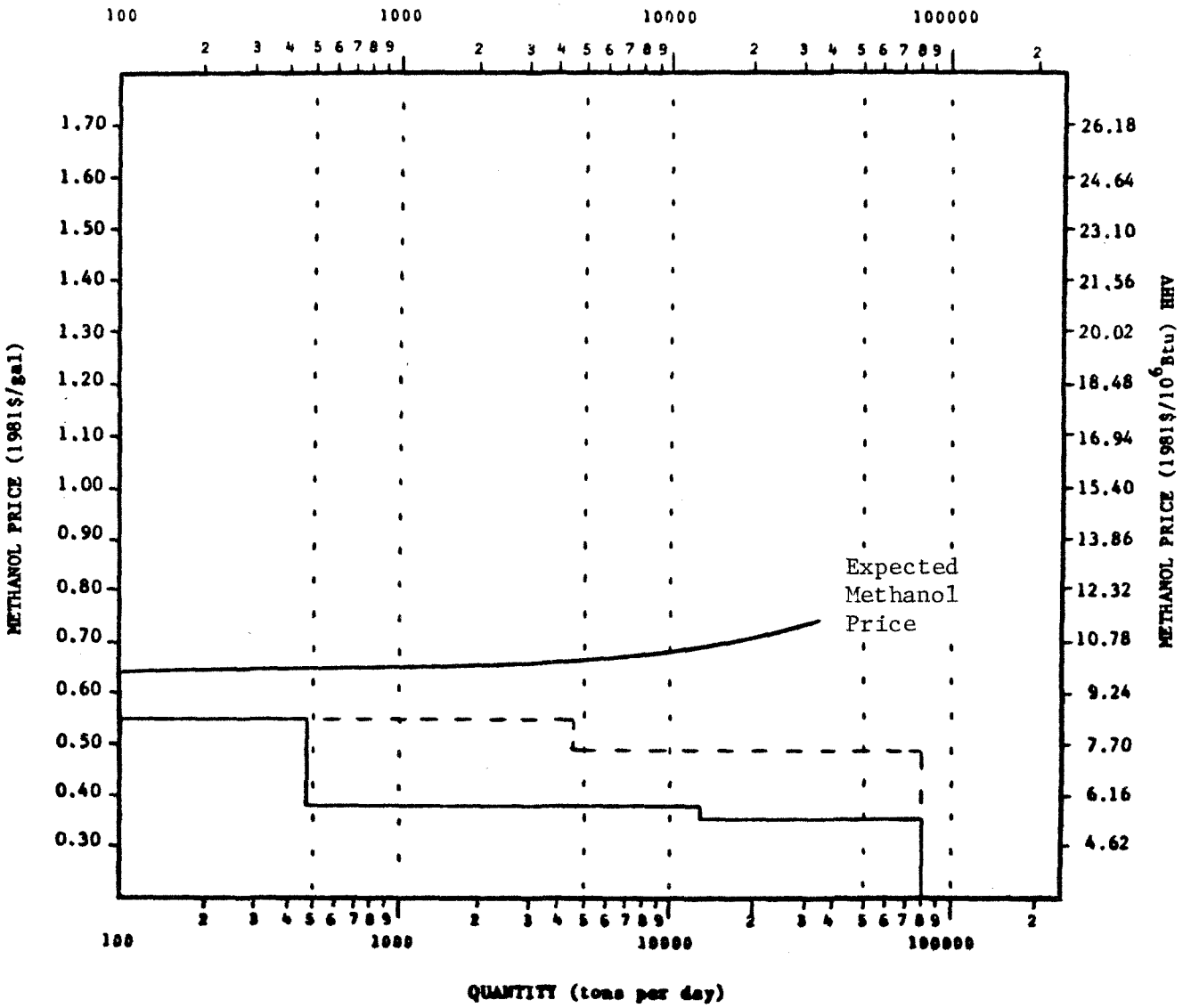
Figure 9-29. 1992 BASELINE SCENARIO INDUSTRIAL METHANOL DEMAND



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

Figure 9-30. 1997 BASELINE SCENARIO INDUSTRIAL METHANOL DEMAND



Natural Gas Available ————————

Natural Gas Unavailable - - - - -

Figure 9-31. 1987 HIGH OIL PRICE SCENARIO INDUSTRIAL METHANOL DEMAND

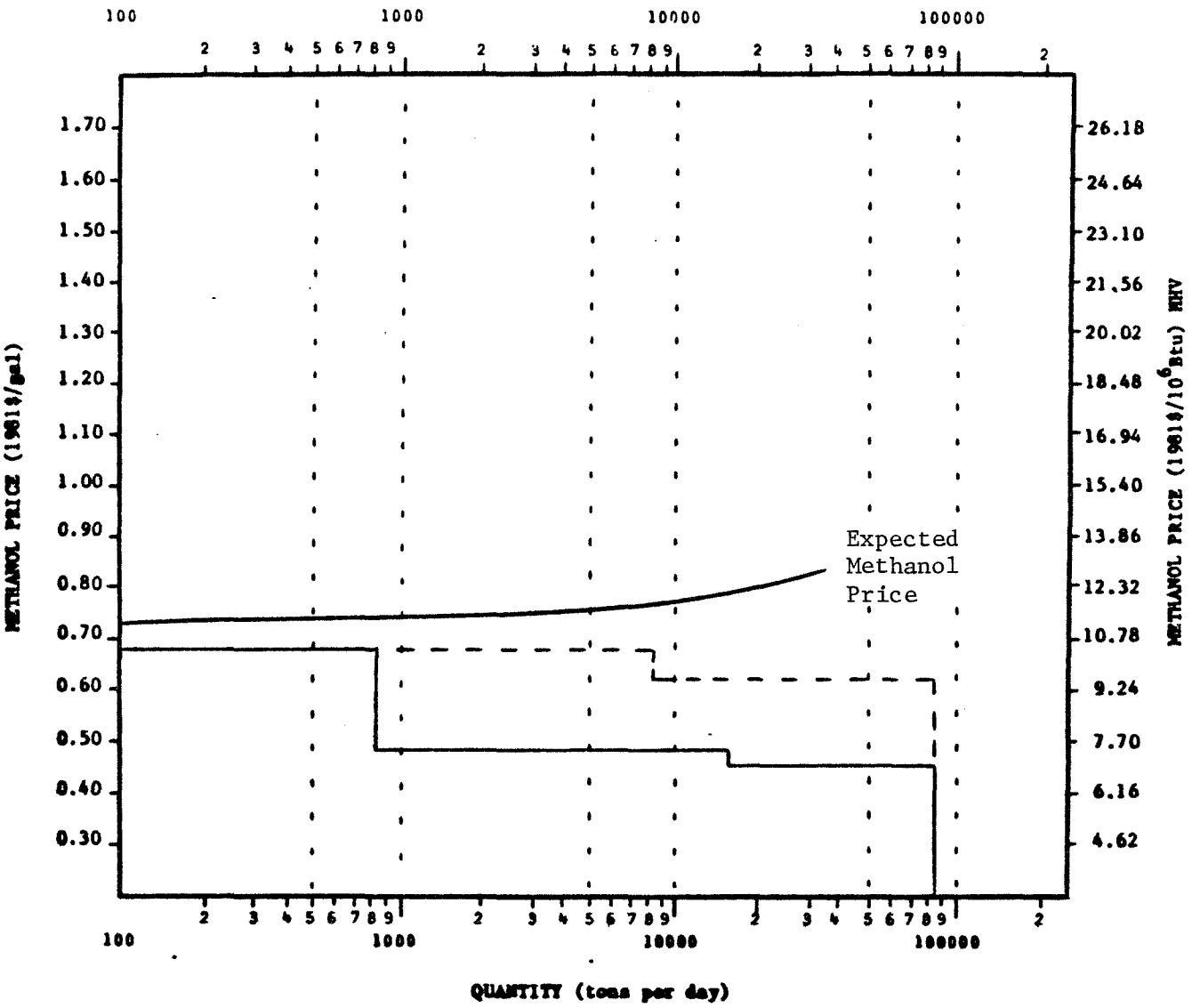


Figure 9-32. 1992 HIGH OIL PRICE SCENARIO INDUSTRIAL METHANOL DEMAND

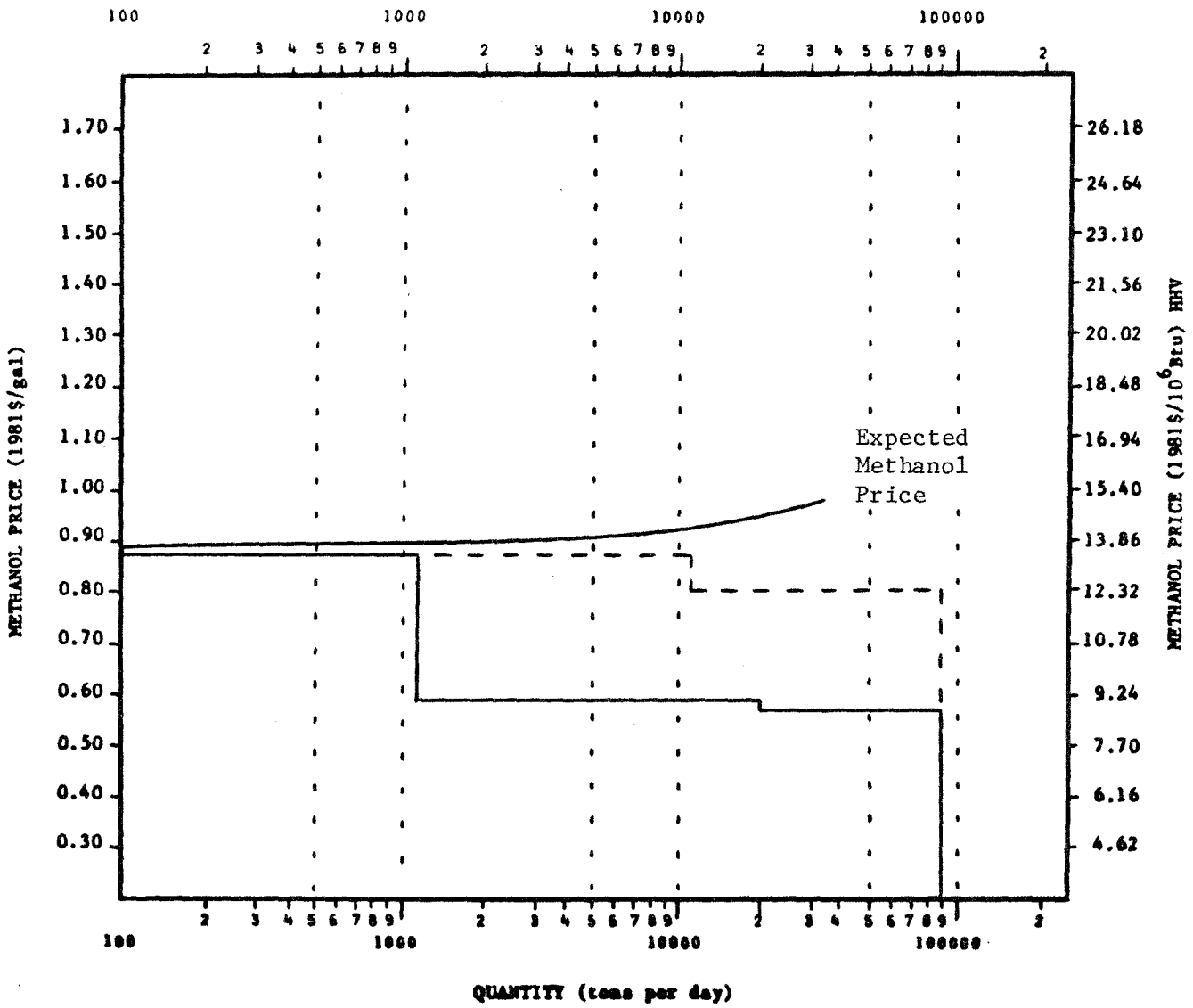


Figure 9-33. 1997 HIGH OIL PRICE SCENARIO INDUSTRIAL METHANOL DEMAND

F. SUMMARY OF BARRIERS AND POLICY CONSIDERATIONS

In the preceding sections a number of barriers which could prevent or delay widespread use of methanol in the stationary sector were identified. In this section these barriers are summarized and the implications of policy options for various government agencies and private organizations that could help overcome these barriers are discussed.

Certainly the most significant "barrier" is the continued availability of natural gas at prices substantially below the lowest projected energy equivalent price of methanol. Substitution of methanol for natural gas in stationary applications, even where environmental benefits can be realized, appears improbable.

Other barriers identified in this study and their policy implications are shown in Table 9-30. The barriers in the table are divided among technological, rate regulation, environmental regulation and general categories. Within categories they are listed in order of apparent significance.

Table 9-30. BARRIERS AND POLICY OPTIONS

BARRIERS	CONSEQUENCES	POLICY OPTIONS		
		OPTIONS	AGENCIES	CONSIDERATIONS
Technological				
1. Early status of development of dual fuel methanol applications. Uncertainties in efficiency improvement and emission reduction.	1. Competitiveness of methanol in these applications cannot be determined, although bench-scale and analytical studies are promising.	1.A. State funding of utility scale demonstration 1.B. Authorization of demonstration cost pass-throughs.	CEC PUC	1.A. Should develop data for oil/gas dual fueling for comparison. 1.B. PUC has resisted such pass-throughs and would have to be convinced of long-term value (see Section D-6)
2. Performance uncertainties in methanol-based repowering.	2. Utilities are reluctant to include this option in resource plans.	2. Additional studies to reduce uncertainties.	CEC	2. Should coordinate with utilities to identify their concerns.
3. Uncertainties in corrosion, maintenance costs and other long-term technical concerns.	3. Cautious approach by utilities resulting in a delayed switch to methanol if cost-effective.	3.A. State funding of long-term turbine test. 3.B. State funding or pass-through of long-term boiler test. 3.C. State funding or pass-through of long-term dual fuel test.	CEC CEC, PUC CEC, PUC	3.A. Relatively inexpensive due to small quantities of fuel. 3.B. Expensive: $10 million/yr. for each $/10^{6}Btu of premium paid for methanol (Mandalay 1). 3.C. Provide most of the information of 3.B. at 10-20% of the cost.
4. Logistics problems in supplying methanol to non-water-supplied parts of SCE system.	4. Uncertainty in break-even cost and in degrees of fuel flexibility that could be retained.	4. State funding of study by SCE.	CEC	
Regulatory - PUC				
5. PUC policy of avoiding subsidizing of future benefits by current ratepayers.	5.A. Methanol must be cost-competitive in first year of multi-year supply contract. 5.B. R&D pass-throughs are minimized. 5.C. Phased development program unlikely before methanol is cost competitive.	5.A. Establish procedures for taking life-cycle costs into account. 5.B. Expand R&D pass-through allowances. 5.C. State funding	PUC/CEC Legislature Legislature CEC/Legislature	5.A. PUC policy change and/or legislative action unlikely in current political situation. 5.B. Same as 5.A. 5.C. Expensive (see 3.B.)
6. PUC opposition to take-or-pay contracts and to fuel supply contracts in which risk is transferred to the rate payers.	6. Potential early suppliers facing cost uncertainties and lack of alternate markets will be reluctant to initiate projects without such contractual provisions.	6. State sponsorship of a working group to develop contract forms acceptable to all parties.	CEC, PUC suppliers, utilities	6. Risks must be shared among suppliers, utilities and rate payers.

Table 9-30. BARRIERS AND POLICY OPTIONS (continued)

BARRIERS	CONSEQUENCES	POLICY OPTIONS		
		OPTIONS	AGENCIES	CONSIDERATIONS
7. Absence of mechanism for paying a premium for use of clean fuels unless in response to specific environmental regulation.	7. Environmental benefits of methanol are not taken into account in fuel selection decisions.	7. State sponsorship of a working group to develop such a mechanism for adoption by legislature.	Legislature (with inputs from CEC, PUC, ARB, SCAQMD, etc.)	7. South Coast Air Basin low NO_x dispatch provides a precedent.
8. Absence of a mechanism for paying a premium for use of a fuel with high security of supply.	8. Long-term security of supply is lightly weighted in fuel selection decisions.	8. Develop such a mechanism.	Legislature (with inputs from CEC)	8. Security of supply would result from production of methanol from coal, which may require a very large premium to be competitive in the utility sector.
Regulatory - Environmental				
9. Utilities are not interested in selling offsets (regardless of profit potential) and industry saves offsets for long-term expansion.	9. The value of methanol in providing offsets remains unrealized.	9. Develop a program to provide incentives to utilities and industry to open up the offsets market.	Legislature and APCD's (with inputs from CEC)	9. Use of dual fuel firing to produce offsets can result in substantial premium, but value is uncertain (see 1).
10. Uncertainty in bubble policies and other environmental regulations, including those responsive to the AQMP.	10. Premiums payable for methanol environmental benefits are hard to estimate.	10. Firm up regulations, but with flexibility to choose the most cost effective control strategies.	APCD's (with inputs from CEC)	10. AQMP development may not have given appropriate consideration to methanol options. This can be rectified by flexible regulations.
11. Subsummation of environmental benefits.	11. Utilities discount the value of environmental benefits of methanol in fuel selection decisions.	11. Provide protection against subsummation by regulatory authorities.	Legislature	11. In the long-run this could be counterproductive to expanded methanol use. More study of this option is needed.
12. Environmental concerns regarding methanol use (evaporative emissions, spills).	12. Regulatory delay.	12. Make a determination that methanol provides net environmental benefits and provide for overriding the concerns listed here (with appropriate mitigation).	Legislature	
General				
13. Perception that the utility market is viewed by suppliers as a stepping stone to the more lucrative transportation market.	13. Concern about long-term availability of methanol at prices competitive with other utility fuels.	13. Develop long-term contracting modes (see 6).	CEC, PUC, suppliers utilities	

G. CONCLUSIONS

Several conclusions can be drawn from the analysis in this report:

(1) The most significant potenital market for methanol (up to 80,000 tons/day) is composed of existing utility steam turbine and combined cycle units which currently fire oil and gas. The actual extent of this market will, of course, depend strongly on future cost and availability of oil and gas. A switch to methanol would be most cost effective for combined cycle units (about 6000 tons/day) which may otherwise have to rely on expensive distillate oil.

(2) SCE is the most likely large-scale utility user of methanol in California because of a large inventory of modern oil- and gas-fired units, strong environmental pressures, and limited long-term access to natural gas.

(3) Existing industrial boilers and heaters (80,000 tons/day), and future industrial cogeneration systems (10,000 tons/day) also represent potential markets for methanol of substantial size, but these currently use natural gas in most cases and have higher priority than the utilities for obtaining gas.

(4) In order for methanol to be competitive in these markets, its price per unit of energy will have to be competitive with the prices of residual oil for utility boilers, distillate oil for combined cycle and industrial units, natural gas (if available), and other synfuels. Some adjustments for such factors as modification costs and environmental benefits will be appropriate in this comparison, but they will probably have a second order effect in the absence of legislative action or a major change in PUC policy. Some exceptions to these statements are discussed in item (5).

(5) Dual-fuel firing may result in payment of substantial premiums for efficiency improvements in all boiler applications. In some speculative situations, the NO_X emission reductions associated with dual fueling could result in very large premiums for methanol (although these may be limited by the performance of gas/oil dual-fuel systems). These premiums are very uncertain because of the early state of development of dual fueling. A state-sponsored test program which would measure emissions and efficiency for methanol/oil and methanol/gas dual fueling in a large boiler and also provide gas/oil data for comparison could play a major role in determining the value of this technology.

(6) Comparing projected methanol prices with demand curves based on oil and gas price scenarios developed in the Summary Report, it is seen that in the baseline scenario methanol will not be competitive with conventional boiler and turbine fuels in the next twenty years (with the possible exception of distillate oil applications under optimistic methanol cost assumptions or extreme scenarios for emission reduction requirements). In the high oil price scenario, methanol would be competitive with distillate by 1995, and marginally competitive with residual oil by the late nineties. It

appears very unlikely that methanol would be competitive with natural gas in stationary applications in the next fifteen to twenty years under either scenario, although the long-term availability of natural gas is not clear.

(7) Repowering of existing steam turbine units with front-end gas turbines and firing methanol in all or part of the system can provide low-cost capacity expansion and emission reductions. Under the high oil price scenario, repowering may have an advantage in cost of electricity over continued operation of the existing system firing either conventional fuels or methanol. (The cost of electricity for repowering would be much higher than for some other options that do not involve use of liquid or gaseous fuels.)

(8) If methanol were to become cost competitive sooner than expected, a phased development period would be expected before the full market potential could be realized. This period would last from four to eight years, depending on the urgency of the circumstances that led to methanol becoming competitive. (The buildup of the methanol supply would probably take longer than this.)

H. REFERENCES

1. California Energy Commission, 1981 Biennial Report.

2. Barbieri, R. H., et al., Process Heat in California, JPL Publication 78-33, March 1978.

3. Egan, T. The Potential for Converting California's Industrial Boilers to Coal, Consultant Report to California Energy Commission, November 1980.

4. Weir, A., von KleinSmid, W. H., and Sanko, E. A., Test and Evaluation of Methanol in a Gas Turbine System, Final Report prepared by Southern California Edison Co. for EPRI, Research Project 988-1.

5. Farmer, R. C., "Methanol-A New Fuel Source?" Gas Turbine International, May-June, 1975.

6. Revty, R. C. and Timbari, T. J., Status of Alcohol Fuels Utilization Technology for Stationary Gas Turbines, report prepared by Mueller Assoc., Inc. for DOE, HCP/M2098-01, April, 1979.

7. Ferrall, J., Pappano, A., and Voecks, G., Methanol for Fuel Cells: Conditions for Availability, June, 1980.

8. Adelman, H. G., Browning, L. H., and Pefley, R. K., "Predicted Exhaust Emissions from a Methanol and Jet Fueled Gas Turbine Combustor," A.I.A.A. Journal, Vol. 14, No. 6, June, 1976.

9. "Aspects of Commercializing Coal-Derived Methanol Fuels in the United States: 1985 to 2000," Vols. I and II, Market Evaluation, prepared by Badger Plants, Inc. for the U.S. DOE, March, 1980, FE-2416-44.

10. Duhl, R. W., "Methanol As A Boiler Fuel," Chemical Engineering Progress, July, 1976, p. 75-76.

11. Duhl, R. W., and Boylan, R. W., Use of Methanol As A Boiler Fuel, paper presented at the Swedish Academy of Engineering Sciences, Stockholm, Sweden, March 23, 1976.

12. Miller, D. R., "Methanol From Coal," Proceedings of the Conference on Coal use for California, JPL Publication 78-56, August 1978.

13. Sema, T., Hoshizawa, K., Sonoda, K., Endo, K., and Mizuochi, H., Study on Methanol Combustion, paper presented at the 4th International Clean Air Congress.

14. Wier, A., et al., Investigation of Methanol as a Boiler Fuel for Electric Power Generation, draft report, EPRI Research Project RP 1412-11, June 1982.

15. Cichanowicz, J. E., Heap, M. P., McMillan, R. E., and Zoldak, F. D., Pollectant Control Techniques For Package Boilers: Phase I Hardware Modifications and Alternate Fuels, Draft Report, EPA Contract 68-02-1498, February, 1977.

16. Martin, G. B., and Heap, M. P., Evaluation of NOx Emission Characteristics of Alcohol Fuels For Use In Stationary Combustion Systems, paper presented at the American Institute of Chemical Engineers Symposium: Impact of Methanol Fuel on Urban Air Pollution, Boston, Mass., Sept., 1975.

17. Foster-Pegg, R. W., Repowering of Large Steam Power Plants with Combustion Turbines Using Coal Derived Methanol and Other Fuels, Draft Report, California Energy Commission Contract 300-79-042, May 1982.

18. Pikulik, A., and Diaz, H. E., "Cost Estimating For Major Process Equipment," Chemical Engineering, Oct. 10, 1977, pp. 106-122.

19. M. Mansour, Personal Communication, KVB Inc., May 1982.

20. Fickett, A. P., "Fuel Cell Power Plants," Scientific American, Vol. 239, No. 6, December, 1978.

21. Abens, S., Lambrech, M., Marchetti, P., Michalko, I., and Patel, D., 1.5 kW Methanol Fuel Cell Power Plant, Final Technical Report for U.S. Army, April 1978.

22. Carlson, C. R., The SYSGEN User Package, JPL Publication 81-47, DOE/JPL-1060-47, March 1981.

23. Slonski, M. L., Energy Systems Economic Analysis (ESEA) Methodology and User's Guide, JPL Report 5101-102, February 15, 1979.

24. Data Resources, Inc., Energy Review, Spring 1982.

25. Southern California Edison Company, Supply Plans for Common Forecasting Methodology III, June 1980.

26. Southern California Edison Company, Common Forecasting Methodology IV Supply Plan, April 1982.

27. Acurex Corp., Alternate Fuel Strategies for Stationary and Mobile Engines, Volume 7, Draft Report #FR-82-109/EE, April 1982.

28. G. Bemis, Personal Communication, California Energy Commission, October 1982.

CHAPTER TEN

ENVIRONMENTAL AND REGULATORY CONSTRAINTS

The purpose of this study is to identify existing and potential environmental regulatory constraints on methanol energy systems for California, and to characterize the environmental, health and safety impacts that may be associated with implementation of methanol energy systems. All aspects of the fuel cycle, from resource extraction through use of methanol as a fuel, are examined in light of current and anticipated environmental regulations and constraints.

Section A of the report provides a general overview of major environmental statues and regulations applicable to methanol energy systems. Sections B through D examine specific issues related to resource extraction, methanol production, and end use of methanol as fuel. Section E compares environmental impacts of methanol energy systems with other synfuels systems, and Section F summarizes the priority environmental constraints on methanol energy systems.

A. OVERVIEW OF APPLICABLE STATUTES AND REGULATIONS

1. Air Quality

The production and use of methanol as a fuel will be subject to an interrelated complex of federal, state and local air quality regulations. The federal Clean Air Act (CAA) provides the basis for most of these laws and regulations, but California has a tradition of air pollution control regulations predating federal activities in this area, and often imposes emission limits that are stricter than federal requirements.

The CAA requires each state to adopt a State Implementation Plan (SIP). Once the SIP is approved by the U.S. Environmental Protection Agency, it has the force of a federal law, but its enforcement is delegated to the state. In California, rules governing emissions from stationary sources are adopted and enforced by local Air Pollution Control Districts (APCDs) under the supervision of the state Air Resources Board (ARB). The ARB is responsible for regulation of mobile sources and for preparing the SIP which includes a compilation of APCD plans and rules. California currently has a SIP in effect, but revisions are required by 1977 CAA amendments. Until these revisions are approved by the EPA, administration of portions of the CAA is in the hands of the EPA.

The following paragraphs discuss the various types of regulations applicable to methanol production facilities and to use of methanol in stationary and mobile applications. The CAA is scheduled for reauthorization by Congress this year, and the Reagan administration is expected to press for significant changes in the law, mainly oriented toward easing the regulatory burden on industry. Thus, some of the detailed provisions described here may be revised in the near future.

a. New Source Performance Standards (NSPS). The EPA has established NSPS for boilers with heat input greater than 250 x 10^6 Btu/hr for stationary turbines, and is developing standards for industrial boilers and possibly for synfuel production plants. These are based on demonstrated technology and represent an upper limit on allowable emissions.

b. Best Available Control Technology (BACT)/Lowest Achievable Emission Rates (LAER). State and local regulations generally require use of BACT on any large project, while the CAA requires use of LAER for projects in non-attainment areas (areas not meeting federal ambient air quality standards) and BACT for very large projects in attainment areas. BACT is determined on a case-by-case basis and takes into account the economics of the project. LAER is defined in the CAA as the lowest emission rate allowed by the SIP of any state (unless the applicant "demonstrates" that such levels are "not achievable") or the lowest rate achieved in practice, whichever is more stringent. LAER could result in requirements on applicants to include in their designs technology that has not been commercially demonstrated and is high on the administration's list of priorities for CAA changes. It should be noted that much variation on these regulations exists: for example, the APCD for the Los Angeles area uses the federal definition of LAER as its definition of BACT. In many cases to date, federal and state agencies have accepted technology satisfying the NSPS as also satisfying BACT or LAER, except in California where state and local agencies tend to push for more stringent emission limits on large projects.

c. Prevention of Significant Deterioration (PSD). The PSD program specifies allowable increments in ambient pollution concentrations for attainment areas. The increments depend on land classifications, with very small degradations permitted in Class I areas (national parks, wilderness areas, other state designated areas), small degradations in Class II areas (most often county), and moderate degradation in Class III areas (none yet designated by state). Class I areas are also protected against any degradation of visibility. New large projects must demonstrate via modeling that they will not cause the allowable increments to be exceeded. PSD could limit the number of large synfuel plants in some western coal resource areas.

d. Offsets. In non-attainment areas, the CAA permits no further air quality degradation. This has led to the concept of "offsets" in which emissions from any new source must be balanced by equal or greater reductions in emissions from nearby existing sources, sometimes leading to a major impact on project costs.

e. Emission Limits for Motor Vehicles. The CAA provides for establishment of highway vehicle emission limits as a function of model year. It also allows individual states to set their own limits as long as they are "at least as protective" as the federal standards. California has set a NO_x standard tighter than the federal standard which has led to significant differences in engine settings between cars sold in California and those sold in the other forty-nine states. Although the Reagan administration is pushing a relaxation of NO_x standards currently to be tightened in future model years, California may choose to keep tightening the NO_x limits.

f. Regulation of Motor Vehicle Fuels. Before any new fuel or additive may be used in motor vehicles, it must be certified by the EPA, based on intensive testing, as not representing a hazard to public health. While neat methanol has not yet been so certified, there is very little indication of potential problems in gaining certification. California also has the power to forbid use of specific fuels or additives, but there is likewise no indication that this will be a hindrance to the use of methanol in vehicles.

In summary, the flexibility built into the current laws and the Reagan administration's desire to change these laws results in substantial uncertainty regarding the air pollutant emission limitations that will be applied to methanol production and utilization systems. However, one generalization can be made for all large energy systems of the future, and especially those in California: It is unlikely that any large energy production or utilization system will be permitted to deviate very far from using the best available emission control technology that does not drastically alter the process economics.

2. Water Quality

Resource extraction, especially coal mining, and methanol production processes produce effluents that may affect water quality and will be subject to a variety of regulations governing water pollution. The primary federal mechanism for protecting water supplies from pollution resulting from industrial discharges is the Federal Water Pollution Control Act and its many amendments, often referred to as the Clean Water Act (CWA) (33 U.S.C. &&1251 et seq.). The basic regulatory mechanism is the National Pollutant Discharge Elimination System (NPDES), which was established with the goals of making U.S. waterways fishable and swimmable by 1983, and achieving zero discharge of pollutants by 1985. Regulations under this program include effluent guidelines, new source performance standards, toxic pollutant regulations, and oil-hazardous substance spills limitations.

EPA has the responsibility to establish point-source effluent limitations for municipal dischargers, industrial dischargers, industrial users of municipal treatment works, and toxic substances. Effluent guidelines and standards, including new source performance standards, are issued for specific industries that discharge conventional pollutants directly into receiving waters. The effluent limitations are technology-based and may reflect best practicable pollution control technology, best conventional control technology, best available technology, or best available technology economically achievable. Generally, limitations are placed on the mass of individually identified substances that can be discharged per unit of product produced. Examples of regulated industries include steam electric power plants, petroleum refining, organic and inorganic chemicals manufacturing, and coal mining.

Under NPDES, states must adopt water quality standards that meet or exceed federal criteria. These water quality standards provide a basis for establishing both point-source based effluent limitations and toxic pollutant limitations used in issuing NPDES permits to point-source dischargers, which include specific discharge limitations for each pollutant discharged by a

facility. States have the authority to issue the permits if federal guidelines and standards are met. Permits can be decided in the absence of guidelines and standards, but such permits may be litigated and the limitations challenged in court by the source discharger.

Sources which discharge to publicly owned treatment works (POTW) via sewers are not covered by the NPDES permit system. Such sources must instead comply with pretreatment standards designed to protect the POTW. Facilities that do not discharge to sewers or surface waters, or which discharge negligible amounts of effluents, are not covered under the NPDES system.

Under the Clean Water Act, EPA is also required to publish a list of designated toxic pollutants, and is authorized to promulgate effluent standards for these pollutants. Approximately 75 toxic substances will eventually have effluent standards. EPA is also authorized to promulgate hazardous spill regulations. EPA has designated as hazardous those discharges which present an imminent and substantial danger to public health or welfare, and has established a system of reporting and fines for operators exceeding discharge limits. Currently, EPA must seek to impose penalties on a case-by-case basis through the courts.

3. Solid Waste

Resource extraction and methanol production processes will undoubtedly generate solid wastes, some of which may be classified as hazardous, which will need to be disposed of in an environmentally acceptable manner. The Resource Conservation and Recovery Act (RCRA) of 1976 (42 U.S.C. &&6901 et seq.) provides the federal basis for regulation of solid and hazardous wastes, particularly industrial wastes. The RCRA program will provide a cradle-to-grave regulatory scheme for hazardous wastes, and provide for the protection of public health and welfare by supplying guidelines to protect the quality of groundwater, surface water, and ambient air from contamination by solid wastes.

Under RCRA, the EPA Office of Solid Waste was given basic authority for controlling the disposal of solid and hazardous wastes. Major elements of the program include:

(1) EPA specification of generic or individual substances considered hazardous.

(2) A "manifest" system under which a manifest is written for each consignment of hazardous waste when it is generated.

(3) A tracking system to follow these consignments until they reach ultimate disposal sites.

(4) A permit system to identify those sites that have adequate facilities to safely dispose of the consignments.

(5) Record keeping and period reporting requirements.

Substances identified as hazardous by the EPA are waste-specific rather than industry-specific. "Hazardous waste" includes those wastes that are ignitable, corrosive, reactive, or toxic. Wastes that are radioactive, infectious, phytotoxic, teratogenic, or mutagenic may also be subject to regulation under RCRA. It is the responsibility of the waste generator to determine if a waste is hazardous; generators of small amounts generally are not subject to regulation under RCRA. The RCRA program prescribes standards and regulations applicable to hazardous waste generators, transporters, and facility owners and operators, as well as storage, treatment, and disposal operations. Construction and operation of any hazardous waste treatment, storage, or disposal facility requires a permit under RCRA.

In addition, under RCRA, the Office of Solid Waste has developed criteria for the disposal of non-hazardous solid wastes in order to protect water and air quality, safeguard environmentally sensitive areas, eliminate disease vectors, and ensure public safety. Under this program, the states are required to survey and evaluate all solid waste disposal sites and develop solid waste plans in accordance with federal criteria. The Office of Solid Waste has developed guidelines for the design and operation of landfills and for surface impoundment of solid waste.

Efforts are currently under way to streamline the waste disposal process by integrating the RCRA waste disposal regulations with other regulatory programs, particularly NPDES requirements under the Clean Water Act, the Safe Drinking Water Act, and the Federal Insecticide, Fungicide, and Rodenticide Act.

As noted above, solid and hazardous waste generators must comply with specific operational standards. However, the Solid Waste Disposal Act Amendments of 1980 exclude from hazardous regulation under RCRA solid wastes from the extraction, beneficiation, and processing of ores and minerals, and solid wasted from fossil fuel-fired electric generating stations. Solid wastes resulting from coal gasification processes are not likely to be classified as hazardous by EPA, but may be by the State of California.

4. Toxic Substances

The Toxic Substances Control Act (TSCA) (15 U.S.C. &&2601 et seq.) authorizes the EPA to obtain information on all new or existing chemical substances and to control any of these substances determined to cause an unreasonable risk to public health or the environment. If warranted, EPA may regulate the manufacture, processing, distribution, use and disposal of these substances. Hazards to be regulated under TSCA include those not covered under other statutes and regulations; therefore, EPA is required to control substances determined to be toxic by authorities given in other laws or even through other agencies, rather than via TSCA.

To date, most emphasis has been placed on obtaining and analyzing information, rather than promulgating control regulations. The program includes (1) development of testing standards and regulations, (2) a premanufacturing notification system, (3) record keeping and reporting requirements,

(4) hazard assessments, and (5) making priority-setting and information systems operational.

Testing procedures are intended to yield information on the physical and chemical properties of substances, health and ecological effects, environmental behavior and fate, likely sources of discharges, technological and economic factors, exposed populations, and industry's risk assessment. Recommendations to EPA on substances to be tested are made by an Interagency Testing Committee, which comprises the EPA, the Occupational Safety and Health Administration (OSHA), the Council on Environmental Quality (CEQ), the National Institute of Environmental Safety and Health, the National Cancer Institute, the National Science Foundation, and the Department of Commerce. To date, a candidate list of approximately 100 existing chemicals not regulated elsewhere has been recommended for detailed analysis, and only two substances are regulated under TSCA: polychlorinated biphenyls (PCBs) and fully halogenated chlorofluoroalkanes.

Under Section 5 of TSCA, persons intending to manufacture a new chemical substance for commercial purposes are required to notify EPA prior to commencing production. Permit requirements and guidelines have been promulgated for premanufacturing notification requirements, review procedures, and premanufacturing testing. EPA has indicated that it will not exempt the synthetic fuels industry from regulations designed to protect the public from exposure to toxic chemicals. Methanol is a well-known and well-characterized substance, but if methanol production processes generate toxic or hazardous substances as by-products or waste stream components that are not covered under other laws, production facilities may be subject to the requirements of Section 5 of TSCA.

5. Health and Safety

Resource extraction for methanol feedstocks, methanol production, and methanol transport are subject to a variety of regulations concerned with worker health and safety. The extraction of coal is regulated by the Mining Safety and Health Administration (MSHA). Though MSHA is responsible for both underground and surface coal mining, the use of surface equipment jointly used in the construction and quarrying industries results in some overlaps between MSHA and Occupational Safety and Health Administration (OSHA) regulations. The MSHA regulations (Title 30, Mineral Resources) generally address equipment design and safe practices for both the use and maintenance of equipment. The oil and natural gas extraction industries are also regulated under OSHA through Chapter 4, subchapters 1 and 14 of the General Industry Safety Orders. These regulations address equipment design and safe drilling/storage practices associated with the extraction of liquids and gases under pressure.

The accumulation and processing of municipal waste and biomass (i.e., the harvesting, compacting and decomposing processes) are controlled by OSHA regulations. These regulations are described in Chapter 4, subchapter 7, under the General Industry Safety Orders, and essentially cover the design and use of the various equipment used in the sanitation and agricultural industries. These regulations generally refer to component design (such as brakes, warning signals, etc.) and total system design (such as safe load

operating limits, designated safe areas for workers, etc.). Also included are safe operation and maintenance practices.

Production processes and resulting plant design for methanol will require conformance with OSHA regulations governing general construction practices (Chapter 4, subchapter 4 of the Safety Orders), design and construction of pressure vessels, pressure lines, pumps and pipelines (Chapter 4, subchapters 1 and 14 of the Safety Orders), design and construction of tanks or pressure vessels for the containment of hazardous substances (Chapter 4, subchapter 7, Groups 8, 16 and 20 of the Safety Orders), and strict conformance with safe practices and personnel protection for handling hazardous substances (Chapter 4, subchapter 7, Group 2 of the Safety Orders). The additional regulations referring to the handling of hazardous substances are required because of the high toxicity and disaster hazard potential associated with methanol and its derivatives, including formaldehyde and formic acid.

The transport of methanol can be done via pipeline or ground carriers (such as trucks). OSHA regulations (Chapter 4, subchapter 15 of the Safety Orders) govern the transport of substances via pipelines. These regulations address the safe design of pipelines, pumps, and valves required for pumping hydrocarbons long distances under pressure. The use of ground carriers to transport hazardous substances is regulated jointly by OSHA and the Department of Transportation (DOT). One factor that may complicate the problem of hazard mitigation is the requirement for mega-methanol plants to produce sufficient quantities of methanol as direct fuel. Plants of this size not only pose reliability problems, but also pose problems in the design of process controls, process monitoring devices, and operation and maintenance procedures for safe plant operation. In summary, it would appear that the methanol production phase would require the most detailed analysis from the standpoint of worker health and safety.

6. Resource Extraction

Coal may play a significant role as a feedstock for methanol production. Environmental impacts of surface mining of coal, as well as surface effects of underground coal mining, are regulated by the Surface Mining Control and Reclamation Act (SMCRA) of 1977. SMCRA mandates the formulation of permit requirements and performance standards for coal mining. States must formulate a regulatory program, approved by the Department of the Interior's Office of Surface Mining, that is at least as strict as the federal standards. SMCRA regulations cover permitting procedures and requirements, mitigation of environmental impacts of mining, and reclamation procedures to be followed after mining.

7. Environmental Impact Assessment Requirements

The federal government and most state governments have enacted legislation requiring assessment of the extent of environmental impacts resulting from government actions, including projects, programs, permits and licenses.

Projects funded by or receiving permits or licenses from federal agencies must comply with the National Environmental Policy Act (NEPA); projects involving state or local agencies must comply with the California Environmental Quality Act (CEQA), which is similar to NEPA. The agency with the widest jurisdiction over a project or the agency funding the project is designated the lead agency and has responsiblity to comply with environmental reporting requirements. Certain aspects of methanol energy systems (i.e., siting, construction, and operation of production facilities) may be subject to CEQA or NEPA requirements. Current emphasis is to coordinate state and federal requirements to eliminate duplication and streamline the process.

This section has emphasized the major federal statues and regulations applicable to methanol energy systems. It must be kept in mind, however, that virtually the entire body of federal environmental legislation is subject to change in the current atmosphere of national regulatory reform. President Reagan's Task Force on Regulatory Relief has targeted many of EPA's regulations for reform, based on information received from the industrial sector on regulations considered most burdensome. Major targets for reform include (1) the Clean Air Act and its many regulations, (2) RCRA's hazardous waste management regulations, (3) criteria and standards for NPDES under the Clean Water Act, (4) pretreatment standards under the Clean Water Act, and (5) TSCA reporting and record-keeping rules. In addition, the Department of Interior may push for major reforms in regulations implementing the Surface Mining Control and Reclamation Act, and reduce the regulatory functions of the Office of Surface Mining. Environmental impact assessment and reporting procedures mandated by NEPA and its guidelines will continue to be administered by the Countil on Environmental Quality, with some possible streamlining of procedures.

California state statutes and regulations are, in many cases, stricter and more long-standing than the federal laws (e.g., air quality and hazardous waste regulation); on the other hand, many state guidelines and standards still need to be formulated. Many permits and licenses are still under the jurisdiction of regional, county, and city authorities.

B. *RESOURCE EXTRACTION*

Most methanol is currently produced from natural gas. However, a greatly expanded methanol production industry for California markets may need to depend upon large quantities of alternative feedstocks, such as remote natural gas, western coal, petroleum coke, and woody biomass, if conventional natural gas supplies diminish or become too expensive. The technology and impacts of natural gas extraction or production, and subsequent methanol production from the gas, are well known. The most likely long-term alternative domestic feedstock to natural gas for large-scale methanol production for California appears to be western coal. Large-scale extraction of coal in the western United States involves a host of environmental and regulatory issues, which are the focus of this section.

1. Land Use and Leasing Constraints

Many factors affect the selection of sites for mining coal in the western United States. For mining coal to be used as methanol feedstocks, the costs of extraction and transportation are likely to be more important factors than coal quality. The type of coal feed used would (1) affect the total tons per day of feed, due to differences in carbon content, (2) affect the size of sulfur recovery facilities, since coals have varying sulfur contents, and (3) affect ash disposal and handling facilities, due to variations in ash content. Much is dependent upon the type of gasifier to be used in the gasification process prior to methanol synthesis. According to industry representatives, KBW gasifiers can accommodate peat, petroleum coke, and any rank of coal; Shell's entrained-bed slagging gasification process can also convert most feedstocks, and Texaco gasifiers can handle some eastern and western coals, lignite, SRC residues, and petroleum coke.

The most important coalfields are likely to be those with thick strippable deposits, relatively close to California. The Yampa/Green River fields in Colorado and Wyoming, the San Juan fields in New Mexico, and the Black Mesa field in Arizona fall into this category (Ref. 17). Much of the coal in these areas may be exhausted after fulfillment of current and anticipated contracts; coal to supply a large California methanol fuel market may need to come from strippable deposits farther away from California (such as the Powder River area) or from deep mines in Utah and Colorado.

The majority of the western coal lands are under the jurisdiction of the federal government. These include lands administered by the Department of Agriculture (U.S. Forest Service) and the Department of Interior (Bureau of Land Management, National Park Service, and the U.S. Fish and Wildlife Service). The Bureau of Land Management is the agency primarily responsible for resource development. In conjunction with the U.S. Geological Service, tracts of land are selected for leasing; a person, association, or corporation can lease a maximum of 46,080 acres of land from the federal government within a state at any one time. These leases are subject to a comprehensive land use plan. A $0.25/acre rental fee, plus royalty payments based on minimum annual production, must be paid to the federal government. In addition, the Surface Mining Control and Reclamation Act (SMCRA) also places land use controls on both federal and nonfederal lands, and establishes performance standards to regulate coal mining. Mining in national parks, monuments, and wildlife refuges is prohibited, subject to valid existing rights and certain other exclusions. Lands administered by the BLM and Forest Service that are undergoing wilderness inventory and study are also subject to restrictions. Alluvial valley floors and prime farming lands are subject to special protection under SMCRA. The individual states must submit coal regulatory programs to the Department of Interior's Office of Surface Mining for approval. States in the west with conditionally approved coal regulatory programs include Colorado, New Mexico, Utah and Wyoming (Ref. 1). Under these programs, in conformance with SMCRA, entities applying for coal leases must submit mine plans, plans for mitigation of impacts during mining, and establish reclamation procedures to restore the land after mining. Coal resources located on Indian tribal lands are subject to constraints and royalties levied by the involved tribal councils.

Table 10-1. FEDERAL LAND MANAGEMENT CONSTRAINTS TO MINING AND SYNFUEL PLANT SITING

CONSTRAINT	RELATIVE EASE OF SITING	LAND CLASSIFICATION
Absolute	Low	National parks
		National monuments
		National wildlife refuges
		National wilderness preservation systems
Severe	Medium Low	Roadless Area Review and Evaluation (RARE II) wilderness (USFS)
		Administration endorsed wilderness
Moderate	Medium	RARE II further planning (USFS)
		National forests and BLM lands
Minor	Medium High	National forests and BLM lands with scattered ownership patterns

(Source: Ref. 2)

An SRI International study for the U.S. Department of Energy (Ref. 2) examined legislative and administrative actions that restrict coal mining and developed four general constraint categories in which federal land management units were placed (Table 10-1). SRI determined the existence of these units and their locations within primary and secondary western coal counties. Results of their analysis indicates that federal land use controls will not seriously constrain siting of coal mines in many areas of the west. In only three counties (Hinsdale, Pitkin, and San Juan, Colorado) do absolute constraints exceed 25% of the total acreage, but in no county does the area so controlled exceed 50%. Two Colorado counties reach the 25-50% level of severely constrained land; neither are coal resource counties. Several coal resource counties have more than 25% of their land in national forests (Sheridan, Wyoming; Bilings and McKenzie, North Dakota; Garfield, Utah; and Gunnison and Routt, Colorado). The only coal resource county with more than 50% of its area under federal control is Gunnison, Colorado, whereas nine non-resource counties have a majority of their surfaces in federal ownerships.

The Four Corners area of Colorado and Utah is the only area where significant conflicts are likely to occur; the northern Great Plains are relatively free of federal lands.

A previous JPL study on potential resources for methanol identified seven western coal regions containing significant resources that could support potential methanol production for California. These regions are (1) Arizona (Black Mesa), (2) southern Utah (Kaiparowits, Kolob-Alton, Henry Mountains), (3) New Mexico-Colorado (San Juan), (4) central Utah-Colorado (Piceance, Uinta, Wasatch, Emery), (5) Wyoming-Colorado (Green River-Yampa), (6) Wyoming-Montana (Powder River Basin), and (7) Alaska). The Black Mesa region is totally under the jurisdiction of the Navajo and Hopi tribes. The mines in this region are operated by Peabody Coal under lease agreements with these tribes. Over a 35-year period, royalties of $76 million to the Navajo and $25 million to the Hopi will be paid. In addition, revenues of $315,000 will be paid to the Navajo for use of 127,750 acre-feet of water to operate the slurry pipeline.

The southern Utah fields are located mainly on federal and state land. Several environmentally sensitive areas (Zion National Park, Cedar Breaks National Monument, Bryce Canyon National Park, and Capitol Reef National Monument) are in the region and may impede development of these coal fields. In the San Juan field, much of the area is owned by Indian tribes, and the rest by the federal government, the state, railroads, and other private parties. It is likely that many of the economic resources in this area also may be depleted due to current contracts.

In the central Utah-Colorado region, lands underlain by coal are mainly federal, state, and privately owned. The Uinta-Piceance areas also have vast oil shale resources on federal lands, and potential conflicts may arise concerning leasing for coal/oil shale extraction. Competition for scarce water supplies may also be a constraint. In addition, many coal resources in this area are high-quality or coking-quality coals, deeply buried and faulted, and may be too expensive to mine for use as methanol feedstocks.

Most of the land in the Green River-Yampa area is federal land, administered by the Bureau of Land Management and the U.S. Forest Service. Parcels of state and private land occur within the federal land. Some of the coal areas are located near Rocky Mountain National Park and other wilderness areas, preservation areas, national wildlife refuges, national monuments, and state recreation areas and parks. In the Powder River region, the federal government administers about 25% of the land; of this land, one-quarter is owned by Indian tribes. Six percent of the land is state-owned, and the remainder is private land. In Alaska, there are almost no privately-owned coal lands. The coal lands are under federal and state jurisdiction.

2. Environmental Constraints

Surface coal mining in the arid and semiarid west is subject to a variety of environmental constraints. Environmental consequences include aquifer disruption, alkaline or salty leachate from the mine site, sedimentation, surface drainage destruction, effects of toxic runoff on ecosystems

and water supplies, erosion, waste disposal, and spoil piles. Fugitive dust emissions and aqueous effluents from coal mining and cleaning operations, spoil piles, and coal storage are regulated by EPA. Coal spoil is currently not classified as hazardous by EPA, but individual states may have more stringent standards that apply to effluents and spoils. Reclamation procedures are established by the states in conformance with the SMCRA, under jurisdiction of the Department of Interior's Office of Surface Mines (OSM). Reclamation on Indian lands is under the jurisdiction of the Indian tribes and OSM. In accordance with regulations, topsoil must be replaced and revegetated after mining is completed, in order to return the land to its previous uses. This can be difficult in the west, where rainfall scarcity may require irrigation in order to reestablish vegetation cover.

Returning the land to its previous use, as required by the SMCRA, is difficult in the semiarid and arid west. Land uses in the Rocky Mountain Province coal-bearing areas include cattle and sheep ranching, dryland farming, some irrigated farming, and forestry, depending on elevation and rainfall. Large tracts are covered by vegetation communities including sagebrush scrub, prairie and grassland, and pine forest. In some areas, irrigation may be necessary during the first year of reclamation to revegetate surface-mined areas with vegetation comparable to that which existed prior to mining. Some areas of higher elevation, such as Black Mesa in Arizona, may not need irrigation for reclamation. Some of the strippable areas in the Green River and Powder River areas may also have sufficient rainfall to ensure reclamation success. Both surface and ground water resources need to be evaluated in the water-scarce areas before mining is planned.

The generally poor soils of the Rocky Mountain Province tend to compound reclamation and revegetation problems. Soil horizons are poorly developed, humus content is low, sufficient topsoil for revegetation is often absent, and erosion rates tend to be high.

Reclamation costs in the Rocky Mountain Province coal-bearing areas average about $3000/acre. Areas with poorer soils and extremely low rainfall may have much higher reclamation costs, or reclamation may not be possible at all (Ref. 23).

3. Health and Safety Impacts

Coal mining is an extremely hazardous occupation, although underground coal mining results in more deaths and disabling injuries than surface mining. In addition, underground coal mining exposes the workers to risks of black lung disease. Surface coal mining is four times safer than underground mining in terms of accidental deaths, and six times safer with respect to injuries. A certain amount of accidental deaths and injuries are associated with coal transportation. Worker exposures to known carcinogenic substances, respirable dust, noise, vibration, heat, fumes, and explosive danger is regulated under the Occupational Safety and Health Act (OSHA) and by the Mining Safety and Health Administration (MSHA). Properly designed and operated facilities and best engineering practices can substantially mitigate worker health and safety problems.

C. METHANOL PRODUCTION

Plants producing methanol for end use in California can be located near the area of feedstock extraction, with the methanol transported via rail, truck, or pipeline to distribution centers in California. Alternatively, the feedstocks, such as coal, can be shipped to methanol production facilities in California. Environmental regulations and constraints affecting methanol production facilities will be dependent on the characteristics of the proposed site, the size of the proposed facilities, the processes used, and the region and state of proposed facility location.

1. Siting Issues

Plant siting constraints will vary depending upon the state in which the facility will be located. California encourages the growth of alternative and synthetic fuels industries, but siting large production plants in California may be difficult due to stringent air pollution and waste disposal regulations and local environmental constraints. In terms of coordinating siting and leasing permits, it may be more feasible to locate methanol production facilities close to the mine mouth. Colorado has a state joint environmental review process to facilitate permitting of synthetic fuels industries through joint project and agency meetings. Through this process, permits may be obtained within a reasonable time. Colorado generally favors synthetic fuels production, but prefers slow, planned development to reduce socioeconomic impacts. Concerned state agencies in Colorado are the Department of Health, which enforces air and water pollution laws; the Air Pollution Control Commission, which sets emission standards and grants permits for construction of facilities; and the Water Quality Control Commission, which regulates discharge of wastes into surface and underground waters (Ref. 16).

Utah also favors synthetic fuels development, but adopts a cautious approach because of their commitment to maintaining high water quality and controlling air pollution, particularly in the four-county Wasatch Front area. Utah is also concerned about mitigating socioeconomic impacts. Environmental standards in Utah are the responsibility of the state Division of Health; policy guidance on environmental regulations in Utah is the responsibility of the state Air Conservation Committee and Board of Health.

Montana tends to have stringent siting requirement and is reluctant to site synfuels plants within its boundaries. Environmental regulation is under the jurisdiction of the Montana Department of Health and Environmental Sciences. In Wyoming, water shortages prompt a cautious attitude toward synthetic fuels development, and property for synfuel plant siting may be scarce. New Mexico has no firm synthetic fuels policy, but appears to offer cautious support. Alaska, which has large coal, oil and natural gas reserves, is supportive of developing means to produce synthetic fuels from domestic resources.

Siting of methanol production facilities must consider the impacts of building a single mine and plant in an area and anticipate the cumulative impacts resulting from a series of mines, plants, and infrastructure. Impacts of methanol production facilities must also be considered in conjunction with

impacts related to mining activities. Factors most critical to the development and siting of synfuels production facilities in the west, from an environmental standpoint, are (1) air pollution control, (2) water availability, and (3) socioeconomic impacts. Air pollution and socioeconomic impacts are discussed in later sections.

Since methanol production may require 5-7 tons of water for each ton of methanol produced, water availability is a critical concern throughout most of the likely areas for siting methanol production facilities in the west. Also, coal slurry pipelines and water-intensive oil shale technologies will compete with methanol production for scarce water supplies. Both physical factors (stream flows, ground water) and institutional factors (such as state allocation policies and Indian water rights) can affect the availability of water for methanol production. In addition, the quantity and quality of waters that may receive plant discharges are other components of the water availability issue. The U.S. Water Resources Council has indicated that the upper Colorado River region has enough ground and surface water to support a synfuels industry producing about 3 million barrels per day. Annual water consumption in this region would increase by about 150,000 acre-feet per year for each million barrels per day of production. Table 10-2 presents the results of the Water Resource Council's assessment of water requirements for synfuels by the year 2000. The Council recommended five alternatives for supplying water for synfuels development--additional development of surface water resources, transfer of water supplies currently used for irrigated agriculture, development of groundwater resources, weather modification to increase precipitation, and more efficient use of water supplies.

Energy companies are looking to the option of transferring water rights from agricultural users, interstate transfers, and speculative leasing of irrigated land to ensure that water will be available for synfuels development. However, economic and political conflicts will persist. Wyoming, for example, has cut the quantities of water available for transfer from agricultural to energy uses. Montana is restricting groundwater withdrawals to rates of annual recharge. Currently, estimates of quantities and prices of western water supplies are uncertain, as are definitions of individual water rights and interpretation of applicable laws. Other studies have indicated that virtually no water may be legally available for synfuels development in Montana and Wyoming. The Crow and Cheyenne Indian tribes hold substantial water rights, and irrigation rights of greater than 15 cf/sec. are not transferable to other uses. If the federal government honors Montana's state water reservations, no water may be available in the state for synfuels development. Generally, estimates of water needs for synfuels plants tend to be just as uncertain as estimates of western stream flows. However, plants can reduce their water needs by using combination wet-dry cooling systems instead of wet cooling systems, and can cut water needs by up to 80% by recycling and conserving water.

2. Air Quality

Clean Air Act (CAA) legislation affecting coal gasification facilities includes new source performance standards (NSPS), prevention of significant deterioration (PSD) for areas attaining the national ambient air

Table 10-2. ANNUAL WATER REQUIREMENTS - 2000
(1,000 acre-feet/year)

SYNFUELS DEVELOPMENT AREA	BASELINE CASE*			ACCELERATED CASE**		
	SYNFUELS DEVEL-OPMENT	ASSO-CIATED GROWTH	TOTAL	SYNFUELS DEVEL-OPMENT	ASSO-CIATED GROWTH	TOTAL
Upper Green River	10.4	4	14.4	23.2	7	30.2
Yampa River	0	0	0	7.5	3	10.5
White River						
Colorado	71.3	19	90.3	136.8	35	171.8
Utah	51.3	0	51.3	68.4	0	68.4
Upper Colorado River Main Stem	22.8	6	28.8	70	14	84
San Juan River						
Colorado	11.2	2	13.2	10.2	2	12.2
New Mexico	50	0	50	50	0	50
TOTALS	217	35	252	373.6	68	441.6

* A baseline case, as defined by DOE, would assume synfuels development would proceed at a "business-as-usual" pace.

** Under an accelerated case, synfuels development would substitute for a greater portion of domestic gas and oil and reduce foreign imports; would have an optimistic degree of success in early market penetration; and production costs would make the product competitive.

Source: U.S. Water Resources Council

quality standards, non-attainment areas (subject to emission tradeoffs), visibility regulations, and state implementation plans (SIPs). Individual states may set more stringent standards than those promulgated by EPA. Pollutants of concern for current and potential regulation include particulates, SO_2, NO_x, CO, stack and fugitive gas, hydrogen sulfide, coal dust and process fines, hydrogen cyanide, ammonia, trace hazardous materials, and aldehydes (Ref. 4). Hydrogen cyanide and ammonia are not criteria pollutants, but may be regulated by individual state implementation plans.

Under NSPS regulations, best available control technology would be required for new facilities. Presently, NSPS for gasification and methanol production facilities do not exist. NSPS do exist for the fossil-fired utility boilers and gas turbines that would supply power for plant operations (see Addendum, p. 10-52). These standards may also apply, as a minimum, to the gasification/methanol production facility in the absence of specific standards.

For facilities that may be located in non-attainment areas (areas that do not achieve the national ambient air quality standards), lowest achievable emission rates (LAER) and offsets are required. This may preclude plant location in many areas in California and other metropolitan areas in the west. LAER is expensive; therefore, facilities may not be sited in non-attainment areas on economic grounds.

Siting permits would be required for facilities locating in or near Class I PSD areas. These are "pristine" areas, such as national parks, that meet national ambient air quality standards. Air quality increment allowances for Class I, II, and III areas exist for SO_2 and particulates. Use of best available control technology and one year of air quality monitoring is required for all new sources. Many areas in the west located near coal resources are in PSD areas. For example, in Colorado, a proposed coal-to-methanol facility (675 tons per day of methanol) located 60 miles south of Steamboat Springs, needed a PSD permit. An SO_2 source, the auxiliary boiler (coal), produced 5 lb/day of SO_2, far below the standard. There were problems with NO_x and CO; these emissions must be monitored. There was no problem with meeting the particulates standard.

In some PSD areas, needed air quality increments may become unavailable. EPA is currently studying strategies to permit energy growth in PSD Class I areas (such as western North Dakota) where increments are exhausted. According to EPA, major expansion opportunities for energy growth may remain under an aggressive offset-purchase program within current Clean Air Act constraints. In the absence of these offsets, it may take CAA revisions relaxing increments restraints to permit siting of pending and future conversion plants. The six options potentially available include offsets, stringent BACT, variances (waivers from Class I increments), BACT with no Class I increment, and elimination of short-term increment regulations.

Visibility protection regulation for Class I areas and "integral vistas" (views that can be seen from mandatory Class I areas) may be a potential constraint on methanol plant siting, but some studies indicate that visibility protection rules will not routinely pose siting constraints for new synfuels plants (Ref. 1). To date, no integral vistas have been officially designated, but the National Park Service has proposed 44 integral vistas from park

service areas. Under the current Administration, the idea of integral vistas may be eliminated, and visibility protection rules would only apply within congressionally designated Class I areas, such as the national parks. States may be given authority over integral vista protection in areas designated by the Department of Interior.

Other studies indicate that EPA's visibility protection rules for Class I areas would have a very site-specific impact on synfuels development; some plants may have to relocate miles away from preferred sites, particularly large coal gasification facilities located within 10 miles of a Class I area. If methanol plants cannot locate close to the mine mouth due to PSD restriction, feedstock transport may make the project infeasible.

The Clean Air Act is targeted for revision by the current Administration. EPA may relax NO_x standards, and is under pressure to relax national ambient air quality standards for ozone. Visibility regulation is also an area of current regulatory uncertainty. Short-term standards for PSD Class I areas may be eliminated. Only four hazardous air pollutants have been defined and regulated by EPA; environmental groups are pushing for 37 more to be regulated under the Clean Air Act. Pollutants of concern for coal gasification facilities include formaldehyde, anhydride, and phenols (see Addendum). Currently, hazardous air pollutant emission standards for synthetic fuel facilities have not been established. Evidence indicates that there may be hazardous species in vent gases and fugitive emissions from gasification processes, but little firm data is available (Ref. 3).

A potential area of concern for gasification/methanol production facilities is CO_2 emissions. These emissions are not currently regulated, but researchers are concerned with long-term effects of increasing CO_2 emissions from energy facilities on global climate trends. A potential area of regulation is acid rain control (Addendum); potential acid rain regulation may affect siting of synfuels plants in the future.

3. Water Quality

Aqueous effluent streams from gasification/methanol production facilities include runoff from coal storage piles and dust control, spent gas quench and cooling water, gasifier blowdown water, process condensate from shift conversion, and waste water such as cooling and boiler blowdown water from associated power generation facilities.

Runoff water from coal storage piles and dust control may contain organic materials and trace elements characteristic of the coal. An EPA study of aqueous effluents from various gasification processes cited 18 potentially hazardous liquid stream pollutants from coal gasification, including phenols, cresol, cyanide, ammonia, sulfides, arsenic, and chlorides (Ref. 7). Spent gas and ash quench waters from gasifiers may contain polycyclic aromatic hydrocarbons (PAH), phenols, other organic materials, and toxic trace metals of known toxicity or carcinogenicity that may exceed present specific effluent limits (Ref. 4). Gas cooling processes may result in water contaminated with suspended organic and inorganic materials (Ref. 3). Many of these contaminants occur in very low concentrations.

Problems associated with pollutants in aqueous effluents can be minimized by recycling the water and planning for zero discharge of effluents. Most current designs for gasification/methanol production facilities incorporate these features. High-Btu Lurgi gasification process plants will produce almost no liquid effluents (Ref. 4). With Koppers-Totzek gasification processes, no special effluent waste treatment is required (Ref. 15). In the Texaco coal-to-methanol process, runoff from coal piles will be collected and used in slurry preparation. Coal is also slurried with recycled process water. In addition, water and particulates removed from the gas are recycled to the coal slurrying unit. Aqueous blowdown from the gasifier unit is processed to environmentally acceptable effluents in wastewater treating units. During shift conversion, process condensate is reheated and returned to the gasification section. The largest amount of waste water produced in this process comes from the power generation facilities (Ref. 6).

The Clean Water Act (CWA) provides for effluent guidelines and NSPS to be established for various point sources of aqueous discharges. These standards have not yet been proposed for coal gasification/methanol production facilities. However, gasifier condensate is very similar to coke plant liquors in chemical composition. Point-source effluent limitations have been established by EPA for aqueous effluents from by-product coking plants under the CWA. Control technologies for regulated constituents of these streams are well-established, and can probably be easily applied to gasifier condensate. Point-source effluent limitations have also been established for certain effluents from petroleum refineries; techniques developed for pollution control of these streams may also be applicable to gasification wastewater. In addition, aqueous effluent streams from associated power generation facilities must comply with effluent guidelines and NSPS for such facilities (Addendum). Point-source discharge permits under the National Pollutant Discharge Elimination System (NPDES) will need to be issued for new methanol production facilities; in the absence of specific standards, permit writers will be guided by standards developed for the similar industries mentioned above, and by state-generated limits for specific receiving waters and pollutants. Planning production facilities to have zero discharge should make permits easier to obtain.

The Clean Water Act is currently targeted for revisions. EPA may recommend (1) pushing back deadlines for water quality goals, (2) allowing waivers from toxic best available technology and conventional best control technology limitations, and (3) extending NPDES permits from 5 to 10 years. States may be allowed to adopt site-specific criteria. While EPA may ease up on regulations, states and local regions may still adopt stringent standards and guidelines of their own.

4. Solid Waste

Solid wastes generated from feedstock gasification/methanol production processes include rock and mineral matter resulting from crushing and sizing of coal; char, tar, slag, and ash from the gasifier; particulates removed from the gas; wastewater treatment and evaporation pond sludges; spent process materials (catalysts and reagents); and ash, particulates, and sludges resulting from associated power generation facilities. Elemental sulfur,

recovered from acid gas treatment processes, can be sold. Coal gasification solid wastes and residues will be produced at the rate of 200 pounds or more per ton of coal feed (Ref. 4). The vast majority of the solid wastes produced from gasification/methanol production facilities will be residual wastes from coal gasification. Incomplete gasification results in the formation of organic solids and tars, which are produced in smaller quantities than slags or mineral residues. Amounts and types of solid wastes generated will depend upon the gasification process.

There are limited data on the characteristics of these solid wastes, expecially concerning the amounts of unreacted coal, trace elements, and organics, and little information on the impacts of handling and disposal of coal gasification solid wastes. Trace elements present in the waste will be representative of elements in the feed coal. An EPA laboratory-scale study and comparison of solid wastes from several types of gasifiers identified 14 solid waste stream pollutants of potential concern (Ref. 7). Gasifier ash may contain the trace elements of arsenic, nickel, beryllium, and selenium. These trace metals may be toxic, but occur in minute amounts. On an equivalent weight basis compared with other gasifier waste streams, the tar stream resulting from some gasifiers may contain significant amounts of toxic, carcinogenic, and mutagenic substances, including polycyclic aromatic hydrocarbons (PAH), other carcinogenic hydrocarbons, and tar bases. Although the tars are produced in smaller quantities than slags and mineral residues, they may require more attention because of suspected carcinogenicity.

Collected particulate matter from gas purification will contain some unreacted carbon, sulfur species, organics, and trace elements. These particulates may contain enough unreacted carbon to serve as a combustion fuel (Ref. 3). Associated utilities will produce solid wastes, such as fly and bottom ash and FGD sludge.

Koppers-Totzek gasifiers and Texaco partial oxidation gasifiers produce no tars or liquid hydrocarbon by-products. In the Texaco process, ash is withdrawn from the gasifiers, sent to an ash dewatering unit, and sent to disposal in landfills. Recovered particulate matter from the gas is recycled to the coal slurrying unit.

Management and disposal of solid wastes must comply with evolving Resource Conservation and Recovery Act (RCRA) standards for nonhazardous and hazardous waste disposal promulgated by EPA. State controls may be more specific and stringent. EPA has not issued specific guidelines for coal gasification facilities, but it appears likely that they will exclude medium-Btu coal gasification wastes from hazardous classification. Gasifier ash may legally fall under the definition of "coal slag," and as such will be considered as nonhazardous. These residues are mostly intractable mineral matter that can be disposed of in sanitary landfills, or sent to lined evaporation ponds with subsequent disposal of the dewatered sludges. Solid wastes from the electrical utility portion of the plant are also currently classified as nonhazardous and can be disposed of in sanitary landfills (Addendum). Solid wastes from coal preparation and sizing are also currently excluded from hazardous designation; these wastes are normally disposed of in landfills. Gasifier ash will probably also be exempt from the Toxic Substances Control Act (TSCA) premanufacturing notification requirements

(EPA has exempted Great Plains Coal Gasification Project gasifier ash from such requirements).

It is highly likely, however, that the California Department of Health will classify coal gasification waste as hazardous, placing additional constraints upon siting of large facilities in the state. Specific handling and disposal procedures will be under the jurisdiction of regional Water Quality Control Boards, leading to site-specific constraints. The concern is over trace elements and organic substances that may eventually leach from the solid waste into water supplies. In Colorado, the Board of Health recently adopted stringent hazardous waste regulations designed to prevent contamination from dumps for 1,000 years (these rules do not apply to private or on-site disposal facilites.) If gasifier wastes are classified as hazardous in Colorado, it may be prohibitively expensive to dispose of the wastes.

Although EPA is currently willing to classify these wastes as non-hazardous, characteristics of the wastes are still not well known. The potential exists in the future for hazardous classification of char, catalyst residue, spent reagents, heavy tar residues, wastewater treatment residues, slag and coal dust residues, and flue gas desulfurization sludge. Spent catalysts containing heavy metals may be restricted under the Toxic Substances Control Act. However, such restrictions are not likely in the near future, since EPA research on health and environmental effects of synfuels technologies will be severely curtailed in the next few years.

5. Health and Safety

Methanol is a well-characterized substance in terms of occupational levels of exposure and safe handling procedures. A value of 200 ppm of methanol in air is estimated as the upper tolerance limit for a steady exposure, eight hours per day, for a single 40-hour week. However, large-scale gasification/methanol production facilities may involve higher levels of exposure to gasification/methanol synthesis by-products. As mentioned in the previous section, gasification products and by-product streams may contain traces of known toxic and carcinogenic substances which have not been characterized in terms of low-level, chronic exposures to workers in these plants, such as might occur in planned facilities. Worker health and safety is covered by OSHA regulations, which regulate worker exposure to hazardous substances, known carcinogens, heat, dust, fumes, noise, vibration, and explosives danger; properly designed and operated facilities, using appropriate control technology and sound industrial hygiene procedures, should result in little risk from known dangers. Regulations also require hazard-specific record keeping and monitoring. However, more research is needed to characterize process streams and fugitive emissions in uncontrolled or malfunction situations, start-up, shut-down and maintenance, the consequences of industrial accidents for these facilites, and exposure and safety risks related to demonstration vs. commercial scale. Researchers recommend the establishment of an epidemiological data base with the initiation of a synfuels industry.

There may also be a public health risk from process products, by-products, and emissions, which may contain carcinogenic or mutagenic

Table 10-3. ANNUAL HEALTH RISKS OF A 1-QUAD COAL GASIFICATION INDUSTRY

PUBLIC HEALTH RISKS		
RISK FACTOR	CONSEQUENCE	RANGE OF EFFECTS
Polycyclic organic matter emitted to air	Excess lung cancer deaths	0-13 excess deaths
Benzene emitted to air	Excess leukemia deaths	0-0.02 excess deaths
Nickel contamination of product gas	Excess lung & nasal cancer deaths	0-0.2 excess deaths
Sulfate exposure resulting from sulfur dioxide emissions	Non-specific premature deaths	0-248 premature deaths
OCCUPATIONAL HEALTH RISKS		
RISK FACTOR	CONSEQUENCE	RANGE OF EFFECTS
Exposure to polycyclic organic matter in the work place	Excess lung cancer deaths	0-5 excess deaths
Accidents	Deaths	9-25
	Injuries	1100-1250
(Source: Ref. 10)		

substances and toxic trace metals. Little data is available on public health risks from synfuels technologies. There is insufficient knowledge in general on the potential of carcinogenic or genetic damage from trace contaminants associated with coal conversion technologies (Ref. 15). Table 10-3 lists the potential public and occupational health risks resulting from a projected 1 quad coal gasification industry.

6. Socioeconomic Impacts

Concern has been expressed over potential socioeconomic impacts of siting large energy facilities in rural, sparsely settled areas of the western United States. A study of conceptual coal-to-methanol plants in Wyoming concluded that development of a methanol industry would result in small towns bearing a large portion of the burden of socioeconomic impact because of

pressures on local utilities and infrastructure, but that county governments would benefit from additions to the tax base (Ref. 19).

In Colorado, a Cumulative Impact Task Force has been established to perform assessments of the socioeconomic impacts of coal, oil shale, electricity generation and other major projects. The task force consists of representatives from state and local government, energy companies, and the Bureau of Land Management. A major goal is to make assessments of the costs and sources of revenue for providing government services for persons migrating to the region to work on projects and provide support services.

D. END USES

In this section, the environmental impacts of end use of methanol as a motor fuel and as utility fuel in California will be discussed. Included are potential health, safety, and public awareness issues associated with use of neat methanol as fuel.

1. Methanol as Vehicular Fuel

Use of methanol as a fuel in vehicles will result in emission characteristics quite different from those of gasoline and diesel fuel. There will also be associated public health and safety considerations, because methanol is different from gasoline in its health risks and toxic effects and has been perceived in the past as an alcohol with potential for use as an intoxicant.

Potential air quality issues associated with use of neat methanol as a motor fuel include increased aldehyde emissions and associated problems of control, toxicity and photoreactivity; impacts and control of unburned methanol in exhaust; and emissions of nitrogen oxides, sulfur oxides, hydrocarbons, and CO as compared to conventional fuel emissions. Characterization of the dispersion, transformation, and transportation of methanol fuel emissions in the atmosphere has not been well defined. The effects of methanol additives on the characteristics of methanol exhaust, such as dimethyl ether and methyl tertiary butyl ether (MTBE), also need to be considered.

A study for the National Alcohol Fuels Commission (Ref. 20) found that methanol does not contribute significantly to the formation of photochemical smog. Mass hydrocarbon and CO emissions may be the same for alcohol fuels as for gasoline, but NO_x emissions from the alcohols are only one-third to two-third of those from gasoline at the same equivalence ratio. Aldehydes, primarily formaldehydes, are the predominant unregulated oxygenated compounds in methanol exhaust. If aldehydes were to be regulated in the future, oxidation catalysts can remove 80-90% from the methanol exhaust; the oxidation catalysts can also effectively remove unburned alcohols from the exhaust.

EPA studies found that pure methanol is a potentially clean-burning automotive fuel that could reduce air quality problems and help alleviate acid rain, due to reduction of NO_x emissions from vehicles. The studies indicated that methanol is environmentally preferable to gasoline and diesel

Table 10-4. ENVIRONMENTAL CHANGES DUE TO METHANOL FUELING

POLLUTANT	CHANGE	IMPACTS
1. Ozone	Large Reduction	o Reduced acute resporatory illness. o Reduced damage to paints, rubber, elastomers.
2. Sulfate	Small Reduction	o Reduced mortality. o Reduced acidity of rain.
3. Sulfur Dioxide	Small Reduction	o Reduced corrosion of metals. o Reduced respiratory illness.
4. Formaldehyde	Large Increase	o No known effects at low concentration. o Possible odor.
5. Nitrogen Dioxide	Significant Reduction	o Reduced acidity of rain. o Possible reduction in respiratory illness.
6. Nitrates	Large Reduction	o Reduced eye irritation.
7. Particulates	Significant Reduction	o Reduced mortality.

fuel because of reduced emissions of nitrogen oxides, sulfur oxides, and particulates. However, coal-based methanol may contain as-yet unknown impurities. EPA also indicated that catalytic converters could eliminate up to 90% of potential aldehyde emissions.

Researchers at the California Institute of Technology performed preliminary air quality modelling studies to determine potential air quality impacts in the Los Angeles Basin resulting from automotive use of neat methanol. Preliminary results indicate that ozone and peroxycetyl nitrate (PAN) levels may be reduced by using methanol in automobiles. Table 10-4 indicates potential environmental changes resulting from methanol fueling, based on the Caltech study.

The overall air quality impacts of using methanol as vehicular fuel are beneficial, but the Reagan Administration EPA is considering relaxation of the current NO_x and CO tailpipe emission standards; this may reduce incentives to using methanol as a fuel.

The potential health and safety impacts of using methanol as a vehicular fuel will need to be carefully assessed before any large-scale introduction of methanol fuel is attempted. Formaldehyde, present in methanol exhaust, is

potentially carcinogenic to humans. The current occupational TLV* is 200 ppm; if concentrations in exhaust approach or exceed this limit, formaldehyde emissions may be regulated. However, as mentioned previously, aldehyde emissions can be controlled by use of catalytic converters. Until recently, formaldehyde was being considered by EPA for regulation under the Toxic Substances Control Act; however, EPA recently decided that risks of formaldehyde exposure were not sufficiently proven to justify regulation. California may still choose to regulate formaldehyde as a hazardous air pollutant.

A potential health risk with methanol fuel may be low-level, chronic methanol leakage from service stations, pipes, valves, fuel pumps, and carburetors. If such leakage is shown to approach or exceed methanol's occupational TLV of 200 ppm, regulatory action may be indicated. Little data exist on the occurrence and impacts of low-level, chronic exposure. New Zealand is currently conducting a trial program on methanol diesel buses; the program includes monitoring of exposure of servicing personnel to methanol, including inhalation and skin contacts. Urine samples of personnel will be tested for methanol levels, and monitoring equipment has been installed in refuelling and service areas. This study may provide needed data on hazards of methanol exposure.

Methanol has a higher flash point than gasoline; therefore, it has slightly less danger of fire in the event of spills and leaks. Except for the need for prevention of ignition of vapors above the liquid fuel in the tank, methanol poses no flammability or explosion hazards not encountered with gasoline. As far as crash safety is concerned, alcohol fuels are safest, gasoline intermediate, and alcohol blends least safe (Ref. 20). However, methanol burns with a nearly invisible flame, and accidental exposure to methanol fires may be a hazard (Ref. 22).

As opposed to gasoline, methanol is extremely soluble in water. Spills would be difficult to clean up, but rapid dilution of methanol with water would help to mitigate the effects of methanol spills.

Some studies have indicated that the toxic effects of gasoline and gasoline components may be more severe than those of methanol. Acute exposures to gasoline through dermal contact, ingestion, and evaporative interactions with eyes, mucocutaneous membranes, and respiratory tissues may be more poisonous, disruptive, and irritating than methanol or ethanol. However, synergistic effects of interactions with methanol and its emissions with drugs, chemicals, and metal pollutants need to be evaluated, and chronic levels of exposures should be evaluated. Table 10-5 compares the toxicities of gasoline, methanol, ethanol, and formaldehyde.

Methanol has occasionally been perceived by certain segments of the population as an intoxicant for potential internal consumption. This problem can be mitigated by public education, addition of disagreeable denaturants,

---

* Threshold limit values (TLV) refer to airborne concentrations of substances and represent conditions under which it is believed that nearly all workers may be repeatedly exposed day after day without adverse effect.

Table 10-5. COMPARATIVE TOXICITY RATINGS

	EYE CONTACT	INHALATION	SKIN PENE-TRATION	SKIN IRRITATION	INGESTION
Gasoline	(2)	(3)	(3)	(1)	(2)
Methanol	2	2	2	1	1
Ethanol	2	1	1	1	1
Formaldehyde	4	3	4	4	3

1 = mild; 5 = extreme toxicity; ( ) = estimated--depends on composition

(Source: Ref. 22)

not labeling methanol as "methyl alcohol," and warnings on containers, pumps, and engines.

2. Methanol as Utility Fuel

Methanol may have environmental performance benefits over coal and other conventional fuels for power generation. If environmental regulations remain stringent or become tighter, methanol use may be encouraged. For example, methanol's zero emissions of SO_2 and low emission of NO_x may make it the preferred utility fuel for control of acid rain if a strong regulatory program is adopted by Congress. This is particularly true in the Northeast and Middle Atlantic areas, but may not be as important for California. Also, utilities wishing to expand facilities in an area which has not attained the national standards for SO_2, particulates, or NO_x may turn to methanol to avoid the need for costly "offsets" (i.e., emissions reductions in existing facilities). California and New York would be particularly good markets for methanol in this situation. If the EPA were to declare tighter emission standards for SO_2 or NO_x, methanol could become a prime fuel for new power plants. Under the current Administration, tighter controls are unlikely; if anything, the current EPA trend is to relax percentage reduction requirements for pollutants.

California is a prime area for broad application of methanol in utilities due to stringent air quality regulations. Methanol has the potential for repowering of existing steam generation plants and for use as a primary gas turbine and boiler fuel. Good initial market locations are in the Los Angeles Basin and other smog-prone areas. However, there may be problems with fuel switching in utilities; alternative fuels may be evaluated at higher plant capacities than existing fuels for environmental regulatory purposes.

Table 10-6. ESTIMATED EMISSION FACTORS FOR PRODUCTION AND COMBUSTION OF METHANOL

	BOILER FUEL (lb/MM Btu coal feed)	GAS TURBINE FUEL (lb/MM Btu coal feed)
SO_2	0.0055	0.0055
NO_x	0.047	0.090
Particulates	0.00171	0.00171
SOURCE: Ref. 12		

Coal gasification followed by methanol synthesis, with end use in a fuel cell, combined cycle or boiler, results in emissions lower than advanced coal-fired power plants, and the potential exists for extremely low emissions (Ref. 12). A summary of emissions factors for production and combustion of methanol utilizing coal gasification is given in Table 10-6.

Methanol fuel has been tested in utility boilers and turbines. In gas turbine peaking facilities, methanol was burned with high efficiency, low NO_x emissions, and no sulfur oxide emissions.

Methanol was also tested as a utility fuel in a two-phase study which assessed NO_x characteristics of a supplementary combined-cycle system, and the effectiveness of combustion modifications to the boiler in reducing NO_x emissions when the turbine and boiler were fired with methanol (Ref. 9). The baseline NO_x emissions with methanol firing were found to be significantly lower than when firing with natural gas. The studies indicated that staged combustion with methanol was effective in reducing NO_x emissions by 50%.

Incentives for using methanol in southern California utilities in order to lessen NO_x emissions may be somewhat reduced as a result of recent agreements between Los Angeles area utilities and state and local air pollution agencies. According to the agreement, a 60% reduction in basin-wide NO_x emissions by 1990 will be attained by reduction of electricity generation in the Los Angeles Basin and purchase of electricity from plants outside the area. However, the utilities may need to rely on alternative energy sources in the future.

E. SYNFUEL COMPARISONS

Assessment of the environmental, health and safety impacts of methanol production and use are most meaningful when compared with other synthetic fuels, and with conventional petroleum and natural gas counterparts.

Tables 10-7 and 10-8 present resource requirements and emissions resulting from several synfuels energy systems, including Lurgi coal gasification, two coal liquefaction processes, coal-to-methanol, coal-to-methanol-to-gasoline, surface oil shale retorting, and ethanol production from corn (Ref. 15). Methanol production appears in the middle of the range for overall resource requirements, but has higher water resource requirements compared to some of the other processes. In terms of emissions, methanol from coal is low in production of SO_2, NO_x and solid wastes, and intermediate in production of CO_2 and particulates compared to production of other synfuels. The same study also developed relative indices of major potential environmental, health and safety impacts for these systems (Table 10-9), and compared projected major annual health and safety impacts for these energy systems (Table 10-10). The coal-to-methanol process ranks low to intermediate in comparison with other synfuels for these impacts.

Utilization of methanol and other synthetic fuels should be compared with petroleum and natural gas for environmental, health and safety impacts. A recent study by Ghassemi, et al. (Ref. 11), focused on potential widespread utilization of synfuels products rather than on technologies and production facility emissions, and compared synthetic fuels with their petroleum and natural gas analogues. The study was based on a realistic synfuels utilization scenario, discussed with major potential synfuel suppliers and users, and industry and government planners. Table 10-11 presents the relative assessment of environmental hazards associated with synfuels products; Table 10-12 presents a priority ranking of environmental concerns associated with the various synfuels products at a projected growth up to the year 2000. Methanol exhibits similar or lower hazards than its petroleum analogues, and is ranked low in environmental concerns compared with other synfuels. Crude shale oil, shale oil refinery feeds, and coal liquefaction fuel oils present the greatest concern.

It must be kept in mind that the environmental data base currently available for synfuels products is very limited. Data on secondary products, such as methanol and gasoline derived from coal, are particularly scarce. There is also a lack of data on the environmental, health and safety characteristics of analogous petroleum and natural gas products that synfuels will replace. Relative rankings of synthetic fuels may change as more data become available. Ghassemi, et al., indicated that research needs for environmental effects of synfuels include (1) a more systematic approach to product characterization and testing so that findings can be correlated, (2) collection of environmental data in conjunction with planned performance testing programs, (3) consideration of end use environmental implications in the selection of the product slates and in the development of the synfuels industry, and (4) compilation of characterization/performance data on analogous petroleum products (Ref. 11).

The West German Environmental Agency has compiled comparisons of air emissions from five representative coal conversion processes. The study indicated that emissions can be controlled to protect the health and welfare of workers as well as the surrounding populations. The study analyzed Lurgi, Sasol, Texaco, SRC II, and modified Bergius processes in plants using best available environmental control technology. The study found that well-known

Table 10-7. ANNUAL RESOURCE REQUIREMENTS OF SYNTHETIC FUEL ENERGY SYSTEMS (PRODUCING ANNUALLY 63 X 10^{12} Btu OF USEFUL ENERGY OR 30,800 BARRELS OF OIL EQUIVALENT PER DAY)

	PROCESSES COMPARED						
	A COAL GASIFICATION LURGI	B COAL LIQUEFACTION FISCHER-TROPSCH	C COAL-METHANOL	D COAL-METHANOL-GASOLINE	E COAL LIQUEFACTION DONOR SOLVENT	F SURFACE SHALE OIL RETORTING TOSCO	G ETHANOL PRODUCTION FROM CORN
Feedstock (corn, coal, or shale) (10^6 tons)	8.5	37.8	23.6	27.0	23.6	128[a]	66[b]
Land (10^3 acres)	58	26	16	18	16	7	24,000[c]
Water (10^9 gallons)	2.0	6.3	7.0	7.6	3.9	4.3	7,300[d]
Ancillary fuels (10^6 barrels)	0.28	2.8	1.8	2.0	1.8	--	320
Manpower							
Peak construction (men)	6,100	15,000	N.A.	N.A.	9,200	3,800	N.A.
Construction (men-year)	14,000	47,000	N.A.	N.A.	29,000	12,000	N.A.
Operation (men)	1,600	11,000	N.A.	N.A.	7,100	2,200	N.A.

N.A. - Not Available

[a] Based on 25 gallons oil per ton of shale.

[b] Based on 21.8 pounds of corn that are required to produce 1 gallon of 199° proof ethanol.

[c] Average production of 100 bushels of corn per acre is assumed, with 56 pounds of corn per bushel, or 2.8 tons of corn per acre.

[d] Assumes that half of marginal land converted to corn production will require irrigation at national average of 1.78 acre-ft. of water per acre of corn.

SOURCE: Ref. 15

Table 10-8. ANNUAL AIR EMISSIONS WITH CONTROLS AND SOLID WASTES FROM SYNTHETIC FUEL ENERGY SYSTEMS (PRODUCING ANNUAL 63 X 10^{12} Btu OF USEFUL ENERGY OR 30,800 BARRELS OF OIL EQUIVALENT PER DAY)

ANNUAL AIR EMISSIONS (10 tons)*	PROCESSES COMPARED						
	A COAL GASIFICATION LURGI	B COAL LIQUEFACTION FISCHER-TROPSCH	C COAL-METHANOL	D COAL-METHANOL-GASOLINE	E COAL LIQUEFACTION DONOR SOLVENT	F SURFACE SHALE OIL RETORTING TOSCO	G ETHANOL PRODUCTION FROM CORN
SO_x	12	74	22	24	36	21	28
NO_x	37	150	90	100	100	20	54
Particulates	2.3	27	70	80	50	12	5.8
HC	0.81	8.6	N.A.	N.A.	N.A.	4.2	1.2
CO	2.3	30	N.A.	N.A.	N.A.	6.9	3.6
CO_2 [a]	11,000	54,000	48,000	52,000	50,000	21,000	17,000
Annual Solid Wastes (10^3 tons)	2,000	8,600	3,400	3,800	2,500	115,000	3,000

* Over the total fuel cycles.

N.A. - Not Available

[a] Hydrogen for coal conversion is not accounted for (e.g., can be produced from nuclear energy). However, if the hydrogen is produced from coal, then the CO_2 figures for coal gasification and indirect coal liquefaction should be increased by about 50%.

SOURCE: Ref. 15

Table 10-9. INDICES OF MAJOR POTENTIAL HEALTH, SAFETY, AND ENVIRONMENTAL IMPACTS FROM UNIT ENERGY SYSTEMS (PRODUCING ANNUALLY 63 X 10^{12} Btu OF USEFUL ENERGY OR 30,800 BARRELS OF OIL EQUIVALENT PER DAY)*

INDEX	RELATED IMPACT	PROCESSES COMPARED						
		A COAL GASIFICATION LURGI	B COAL LIQUEFACTION FISCHER-TROPSCH	C COAL-METHANOL	D COAL-METHANOL-GASOLINE	E COAL LIQUEFACTION DONOR SOLVENT	F SURFACE SHALE OIL RETORTING TOSCO	G ETHANOL PRODUCTION FROM CORN
Annual quantities of mined coal (10^6 tons/year) public impact from transportation	Occupational mining impact (CWP and mining accidents); general	8.5	37.8	23.6	27.0	23.6	N.A.	N.A.
Annual emissions of SO_2 (10^3 tons/year)	General public impact from combustion products; damages to environment; damages to property and agricultural products	12	74	22	24	36	21	28
Annual emissions of CO_2 (10^6 tons/year)	Long-term weather modification	11	54	48	52	50	21	17
Land use (10^3 acres per year)	Damages to land Socioeconomic impact Competing land uses	58	26	16	18	16	7	24,000
Peak construction Manpower (men)	Socioeconomic impact Community growth	6,100	15,000	N.A.	N.A.	9,200	3,800	N.A.
Operational Manpower (men)	Socioeconomic impact Community growth	1,600	11,000	N.A.	N.A.	7,100	2,200	N.A.
Water consumption	Socioeconomic impact	2.0	6.3	7.0	7.6	3.9	4.3	7,300

* These figures do not include CO_2 production from H_2 generation for gasification or liquefaction processes. An additional amount of CO_2 (approximately 35% by weight) derives from these sources.

N.A. - Not Available

SOURCE: REf. 15

Table 10-10. MAJOR ANNUAL HEALTH AND SAFETY IMPACTS (CASES/YEAR) FROM UNIT ENERGY SYSTEMS (PRODUCING ANNUALLY 63 X 10^{12} Btu OF USEFUL ENERGY OR 30,800 BARRELS OF OIL EQUIVALENT PER DAY)

	PROCESSES COMPARED						
	A COAL GASIFICATION LURGI	B COAL LIQUEFACTION FISCHER-TROPSCH	C COAL-METHANOL	D COAL-METHANOL-GASOLINE	E COAL LIQUEFACTION DONOR SOLVENT	F SURFACE SHALE OIL RETORTING TOSCO	G ETHANOL PRODUCTION FROM CORN
IMPACTS							
OCCUPATIONAL HEALTH IMPACTS							
Disease deaths from extraction	12	53	33	36	33	N.A.	N.A.
Damage to health from extraction	290	1,300	810	900	810	N.A.	N.A.
Accidental deaths from extraction	1.9	8.5	5.3	5.8	5.3	9.6	N.A.
Accidental injuries from extraction	140	630	390	430	390	700	N.A.
Accidental deaths from transportation	0.71	3.2	2.0	2.2	2.0	N.A.	N.A.
Accidental injuries from transportation	9.2	41	25	28	25	N.A.	N.A.
GENERAL PUBLIC HEALTH IMPACTS							
Accidental deaths from transportation	6.4	28	18	20	18	N.A.	N.A.
Accidental injuries from transportation	83	370	230	250	230	N.A.	N.A.
Disease deaths from emissions	8.2	50	24	16	24	14	19
Aggravation of asthma from emissions	12,000	73,000	21,000	23,000	35,000	0-21,000	0-27,000

N.A. - Not Available

Numbers refer to relative indices used, and are not to be interpreted as statistical mortality estimates (data not yet available). Also, indices do not reflect impacts of control technologies/procedures which can significantly decrease health impacts.

SOURCE: Ref. 15

Table 10-11. RELATIVE ASSESSMENT OF ENVIRONMENTAL HAZARDS[a]

PRODUCT	EXPOSURE[b]		EMISSION FACTOR[b]		TOXIC HAZARD[b]		COST OF CONTROL[b]	ADEQUACY OF EXISTING REGULATIONS[c]			
	TRANSPORT AND STORAGE	END USE	TRANSPORT AND STORAGE	END USE	TRANSPORT AND STORAGE	END USE		CAA[d]	CWA[e]	RCRA[f]	TSCA[g]
Crude shale oil (fuel)	+	0	0	+	+	+	+	+	+	+	0
Shale oil refinery feed	+	0	0	0	+	+	0	0	+	+	0
Shale diesel fuel	0	0	0	+	0	+	+	+	0	+	0
Shale residuals	0	0	0	+	+	+	+	+	+	+	0
Shale gasoline	0	0	0	+	0	+	+	+	0	+	0
Low-/medium Btu gas (coal)	0	0	0	+	+	+	+	+	0	+	0
SNG (coal)	0	0	0	0	0	0	0	0	0	0	0
Gasifier tars and oils	0	0	0	+	+	+	+	+	+	+	0
Gasifier phenol	0	0	0	+	+	+	0	0	0	0	0
F-T LPG	0	0	0	0	0	0	0	0	0	0	0
F-T medium Btu gas	0	0	0	0	0	0	0	0	0	0	0
F-T SNG	0	0	0	0	0	0	0	0	0	0	0
F-T heavy fuel oil	0	0	0	0	0	0	+	0	0	+	0
F-T gasoline	0	0	0	0	0	0	0	0	0	+	0
Mobil-M gasoline	0	0	0	0	0	0	0	0	0	+	0
F-T diesel fuel	0	0	0	0	0	0	0	0	0	+	0
Fuel methanol	0	0	0	0	0	0	0	0	0	0	0
SRC-II fuel oil	+	0	0	+	+	+	+	+	+	+	0
SRC-II naptha	0	0	0	0	+	+	0	0	+	+	0
SRC-II LPG	0	0	0	0	0	0	0	0	0	0	0
EDS fuel oil	+	0	0	+	+	+	+	+	+	+	0
EDS naptha	0	0	0	0	+	+	0	0	+	+	0
EDS LPG	0	0	0	0	0	0	0	0	0	0	0
H-coal fuel oil	+	0	0	+	+	+	+	+	+	+	0
H-coal naptha	0	0	0	0	+	+	0	0	+	+	0
H-coal LPG	0	0	0	0	0	0	0	0	0	0	0

a - Associated with synfuel products and petroleum analogues
b - 0 = similar or lower hazard than petroleum analogue,
+ = greater hazard than petroleum analogue
c - 0 = regulations are adequate, + = regulations are inadequate
d - Clean Air Act
e - Clean Water Act
f - Resource Conservation and Recovery Act
g - Toxic Substances Control Act

SOURCE: Ref. 11

Table 10-12. PRIORITY RANKING OF SYNFUEL PRODUCTS FROM THE STANDPOINT OF ENVIRONMENTAL CONCERNS*

Product	1980-1987	1988-1992	1993-2000
Crude shale oil (fuel)	2	-	-
Shale oil refinery feed	1	1	1
Shale jet fuel	2	2	2
Shale diesel fuel	2	2	2
Shale residuals	2	2	2
Shale gasoline	2	2	2
Medium-Btu gas (coal)	2	2	1
SNG (coal)	3	3	3
Gasifier tars, oils	-	1	1
Gasifier phenol	2	2	2
F-T LPG	-	3	3
F-T medium-Btu gas	-	3	3
F-T SNG	-	3	3
F-T heavy fuel oil	-	3	3
F-T gasoline	-	3	3
Mobil-M gasoline	-	3	3
F-T diesel fuel	-	3	3
Fuel methanol	-	3	3
SRC-II fuel oil	-	1	1
SRC-II naptha	-	2	2
SRC-II LPG	-	3	2
EDS fuel oil	-	-	1
EDS naptha	-	-	2
EDS LPG	-	-	3
H-coal fuel oil	-	-	1
H-coal naptha	-	-	2
H-coal LPG	-	-	3

* Degree of concern: 1=most, 2=modest, 3=low; (-) indicates product not produced or not used as indicated.

technologies used in oil refining appear to be applicable to the production of synfuels.

EPA has performed relative assessments, comparing methanol with the Mobil methanol-to-gasoline process, Exxon Donor Solvent, H-coal, and SRC-II direct liquefaction processes. Methanol was found to be both cheaper and environmentally cleaner than other synthetic transportation fuels derived from coal. EPA also found that indirect liquefaction processes appear to facilitate the removal of environmentally damaging substances. Gasification processes place most of the potentially harmful substances into forms which can be removed with relative ease. In addition, methanol engines promise lower emissions of NO_x and absence of particulate matter. Coal liquids, in contrast, are more aromatic and contain significant quantities of organic compounds; some of these compounds have been shown to be mutagenic in bioassays. Indirect liquefaction products do not appear to exhibit mutagenicity or carcinogenicity, although methanol is highly toxic in heavy exposures.

Currently, EPA appears to be withdrawing from making synfuels policy decisions and from expressing a preference for methanol over other synfuels. Overall work on pollution control technology development for synfuels is expected to decrease, although some research on health effects of oil shale and coal liquefaction processes may increase. EPA is not presently planning to issue environmental standards governing synthetic fuels technologies, and no synfuels pollution control guidance documents for industry will be issued, although some technical documents may be published. In the future, EPA may attempt a unified approach to synfuels regulation, combining air, water, and solid waste regulations.

F. METHANOL POTENTIAL IN CALIFORNIA AIR QUALITY PLANNING

1. Introduction

Under the Clean Air Act, the U.S. Environmental Protection Agency has set primary and secondary national ambient air quality standards for six air pollutants: sulfer dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), total suspended particulates (TSP), ozone, and lead. EPA requires each state to submit for approval a State Implementation Plan (SIP), which outlines how the state will achieve or maintain the national ambient air quality standards. Because the original 1977 compliance date for achievement of the national standards was not met, the 1977 Clean Air Act amendments set a new final compliance date of December 31, 1982. Extensions of the final compliance date to 1987, only for the ozone and carbon monoxide standards, are allowed if the state implements certain specific control measures which EPA and Congress have determined to be "reasonably available" (Ref. 24).

The federal standards function as minimum standards for air quality; state standards must be at least as stringent as the federal standards. California's SO_2 and ozone standards are stricter than the federal standards. In addition to the six air pollutants regulated by the EPA, California has also established air quality standards for ethylene, hydrogen sulfide, sulfates, visibility-reducing particulates, and vinyl chloride (Ref. 25). The regulatory picture can become quite complicated due to the interaction of

federal, state, and regional entities, and the severity and public perception of the individual state's air pollution problems. Thus, regulatory constraints and incentives to methanol use can vary widely from state to state.

In California, overall authority for state air quality planning and SIP preparation and submission rests with the California Air Resources Board (ARB). The ARB has divided the state into 14 air basins, represented by regional air pollution control districts, air quality management districts, and other local and regional governments. Regional planning authorities have primary responsibility for control of air pollution from stationary sources, and for devising plans to bring the regions to attainment of the air quality standards. ARB is responsible for approving the regional plans, rules and regulations, and for incorporating them into the SIP. ARB also has primary responsibility for setting statewide motor vehicle emission standards. ARB takes a relatively active role in assisting the regions in preparation of the air quality management plans, and sets guidelines for the regions to follow.

The planning agencies must submit annual reports demonstrating reasonable further progress toward attainment of the NAAQS. In addition, air quality monitoring is needed to verify that the planned emission reductions are being carried out at a reasonable and sufficient rate. Requirements of plans include establishment of interim air quality goals, long-range plans for attainment, and updates of the air quality management plans every five years until the standards are met (Ref. 25).

The following sections evaluate the potential contribution of methanol fuel use in California's efforts to devise strategies to meet air quality standards. Methanol potential was evaluated from the statewide (CARB) perspective, and for two major regions in California: the Bay Area Air Quality Management District (BAAQMD), and the South Coast Air Quality Management District (SCAQMD). Both of these regions have recently revised their air quality management plans.

2. The Statewide Perspective: Methanol Potential

The 1979 State Implementation Plan requires that the state implement certain procedures to demonstrate progress toward attainment and maintenance of the NAAQS. These requirements are as follows:

(1) Inventory of Emissions from all existing sources of air pollution.

(2) Air Quality Analyses and Forecasts.

(3) A demonstration that the plan will achieve "Reasonable Further Progress" in reducing emissions during each year between 1979 and the final compliance date.

(4) Reasonably Available Control Measures for industrial facilities.

(5) Permit Program for industrial sources including a New Source Review rule for new facilities.

(6) Emissions Growth Allotments for the construction or the modification of major industrial sources.

(7) Uniform Population Growth Assumptions for the SIP and other plans which affect or are affected by population growth.

(8) An analysis of the Plan Effects on the environment and the economy.

(9) Evidence that Consultation with the general public and local governments has occurred during the development of the plan.

(10) Evidence that Resources Commitment sufficient to carry out the plan has been made.

(11) Evidence that the Adoption of the plan by agencies responsible for its implementation has occurred.

The 1979 forecast for 1987 air quality in the state's air basins indicates that the ozone and CO standards in the South Coast Air Basin, and CO in the Lake Tahoe Air Basin, will not be attained by the deadline using control measures already adopted or ready for adoption. It is unlikely that the standards will be attained even with development of further control measures (Ref. 24). An extension of the attainment deadline to 1987 (for ozone and CO) can be granted by EPA if the following measures are incorporated into the SIP as amendments:

(1) Commitment to providing adequate Public Transit.

(2) Commitment to adopt Transportation Control Measures.

(3) A Motor Vehicle Inspection Program requiring the annual inspection of all cars and light-duty trucks and the correction of defects which increase emissions.

(4) Existence of an Industrial Facility Siting Program.

(5) A list of Other Measures sufficient to meet the air quality standards by the final compliance date.

Transportation vehicles are responsible for slightly less than one-half the problems related to hydrocarbon and nitrogen oxide emissions (potential contributors to ozone formation), and cause most of the CO problem. Under measure (2) above, 18 "reasonably available" transportation control measures are required to be considered by the state, if an extension to 1987 for compliance with the ozone and CO standards is required (Ref. 26).

One of the required control measures is the conversion of fleet vehicles to alternative fuels or engines, or to otherwise control emissions from fleet vehicles. It is the policy of the state to foster methanol use in fleet vehicles, on an experimental bases, as a replacement for gasoline and diesel fuels. The ARB believes that methanol can be used as a low emissions fuel, because it has demonstrated the potential for lower CO and nitrogen oxide

emissions (in gasoline engines). It appears that hydrocarbon emissions from methanol vehicles will be no more reactive than those from gasoline engines, and may be less reactive (Ref. 27). However, ARB believes that more research needs to be done on methanol engines before use can become widespread.

There are no statutory impediments to the development of methanol vehicles in California since existing laws clearly recognize methanol as a legal motor vehicle fuel. Section 5115 of the California Motor Vehicle Code states:

> "Notwithstanding any other provision of law or any regulation, methanol fuel, or methanol fuel and gasoline blends, shall be considered a legal fuel in California." (Ref. 27)

Subsequent sections encourage the use of methanol on an experimental basis. In addition, the State Department of Motor Vehicles is authorized to establish an eleven-year methanol fuel experimental program. Each participating experimental vehicle is required to have a valid Certificate of Compliance from a licensed motor vehicle pollution control device installation and inspection station, indicating that the emission control system is in compliance with the Health and Safety Code. All reasonable engine modifications (except for tampering with exhaust emission control systems) are permitted in order to allow the use of alcohol fuels as motor vehicle fuels (Ref. 27).

Under current California law, exhaust emission standards for gasoline-powered vehicles also apply to vehicles which have been modified to use other fuels. In addition, under present law, ARB is authorized to adopt standards and test procedures to certify fuel systems of vehicles powered by fuels other than gasoline or diesel. Establishment of these standards and procedures is necessary for large-scale, rather than experimental, implementation of alternative fuel systems. Such standards have already been adopted by ARB for liquefied petroleum and natural gas fuels conversion systems. In November 1982, ARB proposed standards and procedures for certification of alcohol and alcohol/gasoline conversion systems (Ref. 28). The proposed procedures cover methanol and ethanol fuel systems, dual-fuel methanol/gasoline systems, dual-fuel ethanol/gasoline systems, and systems using methanol/gasoline or ethanol/gasoline blends. The need to evaluate alcohol conversion systems stems primarily from the potential for increased emissions and reduced engine durability. Requirements of the proposed standards are as follows:

(1) Conversion system manufactures will be required to test a minimum of three, but not more than 10, vehicles per vehicle class for each alcohol conversion system. Emissions from modified vehicles may not exceed emission levels found in the baseline test.

(2) Conversion system manufacturers may be required to evaluate vehicle driveability and durability.

(3) There will be no limits placed on the number of modifications a conversion system manufacturer may make to a vehicle converted to use methanol or ethanol, so long as the modifications do not increase emissions.

(4) Vehicles participating in the Methanol Fuel Experimental Program established pursuant to Vehicle Code Sections 5115.5 and 5116 are not required to have a certified conversion system. However, the owner or lessee of the vehicle must obtain an annual Certificate of Compliance indicating that the vehicle's emissions are in compliance with state standards. ARB has proposed guidelines for issuance of Certificates of Compliance for methanol-powered experimental vehicles (Ref. 28).

While there are few regulatory impediments to the use of methanol in vehicles on an experimental basis, widespread conversion of vehicles to use methanol will require manufacturers and sellers of methanol conversion systems to undergo the process of certification by the ARB.

Replacing portions of the fleet with advanced low-emissions technology vehicles is part of ARB's overall mobile service emission control strategy, which also includes reducing excess emissions from regulated sources, lowering standards for regulated sources and adopting standards for unregulated sources (Ref. 29). Applications of this strategy in the South Coast Air Basin, and potential methanol applications, are discussed below under Regional Strategies.

State exhaust emission standards (for hydrocarbon, CO, and nitrogen oxides) for vehicles of 1989 and later model years are tighter than for previous models. In many cases the standards are more stringent than federal standards (Ref. 30). The ARB has recently tightened the NO_x and particulate standards for diesel-powered passenger cars, light-duty trucks, and medium-duty vehicles. The new NO_x standard of 1.0 grams per mile (gpm) will apply to 1984 model passenger cars and light-duty trucks that are certified to 100,000 miles. The new particulate standard of 0.4 gpm will be effective for 1985 models; the standard will be tightened to 0.2 gpm for 1986 models and 0.08 gpm in 1989 and subsequent model years (Ref. 31). Vehicle manufacturers claim that emission control technology for diesels is uncertain and that there may be problems in meeting the standards. Diesels can meet the hydrocarbon and CO standards, but have difficulty in controlling NO_x and particulate emissions. To compensate for this difficulty, ARB will allow manufacturers to submit tradeoff proposals to reduce NO_x emissions from gasoline-powered vehicles to compensate for emissions from diesel vehicles. Guidelines for this option are currently being developed by ARB. Methanol-powered vehicles may make a contribution to arranging these tradeoffs if the number of diesel-powered vehicles continues to increase as the exhaust emission standards are tightened.

As mentioned previously, control of emissions from stationary sources is primarily the responsibility of individual air pollution control regions in the state. However, exemptions from the general emission limitations contained in Article 1, Chapter 3, Part 4, Nonvehicular Air Pollution Control, of Division 26 of the California Health and Safety Code exist for certain methanol fuel manufacturing plants. Exempt facilities include methanol fuel plants which manufacture not more than 2,000,000 gallons of methanol fuel per day from wood, agricultural residues, natural gas, or coke (exclusive of petroleum coke). However, only one such plant is allowed in each air basin, the plant must be located in an area that has attained the NAAQS under the Clean Air Act, and the plant must meet all applicable standards required by the district board (Ref. 32).

3. Regional Strategies: Methanol Potential

a. Bay Area Air Quality Management District (BAAQMD). The BAAQMD, the Association of Bay Area Governments and the Metropolitan Transportation Commission have recently revised and updated the 1979 Air Quality Management Plan for the district, and issued a draft for comment (Ref. 33). The final plan should be out in December 1982.

The federal standards for ozone and CO are currently exceeded in the Bay Area. The SO_2 and NO_2 standards are met, and are not expected to be a problem in the future. Thus, the recommended control strategies of the BAAQMD are aimed at reducing hydrocarbon and carbon monoxide emissions.

Twenty-two new regulations were proposed by the BAAQMD for control of stationary source emissions, and an additional twelve were proposed as contingencies. The thrust of the proposed regulations is to reduce hydrocarbon (especially volatile organic compound) emissions from industrial sources. No mention is made of using methanol or any other alternative fuel in industrial or utility stationary applications. A proposed measure to reduce emissions from large stationary sources by 10 percent below the present baseline was rejected, due to expectatons that an arbitrary reduction of 10 percent may not be achievable, and could be very expensive.

Fifteen transportation control measures were proposed for implementation. Again, no specific measures encouraging methanol or other alternative fuel use were proposed. Most of the measures are aimed at increased use of ridesharing, public transit, and zoning. However, transportation control measure No. 15 demonstrates a commitment to "disseminate information on the economic and technical benefits of alterative engines and fuels to fleet operators in the Bay Area" (Ref. 33). The three worst areas of CO concentrations (San Jose, Oakland, and Vallejo) have additional recommended strategies for CO control, but none of them involve use of alternative fuels.

Conversion of fleet vehicles to cleaner engines or fuels in the Bay Area was not selected by the BAAQMD as a candidate mitigation measure for several reasons. It was believed that there would be difficulties in implementation and enforcement resulting from the fact that vehicles are registered with the state rather than with local jurisdictions, and that fleet vehicle conversion programs would be most effectively implemented by the state. Also, the benefits were perceived to be small, because the percentage of fleet vehicle miles is a relatively small percentage of the total vehicle miles. In addition, the Bay Area's Metropolitan Transportation Commission policy supports measures that would improve or enhance automobile alternatives (such as rapid transit, carpooling, and bicycling) without penalizing those persons dependent upon conventional automobiles.

It appears that there are few, if any, incentives to use methanol as a fuel in either stationary or mobile applications in the Bay Area, as indicated by the 1982 Bay Area Air Quality Plan.

b. South Coast Air Quality Management District (SCAQMD). As indicated earlier, the South Coast Air Basin has serious air pollution prob-

lems and will encounter severe difficulties in attaining air quality standards by the compliance dates (1982 for NO_x; 1987 for CO and ozone). The SCAQMD and the Southern California Association of Governments have recently approved a 1982 revision of the 1979 Air Quality Management Plan for the South Coast Air Basin (Ref. 25). The primary goal of the Plan is attainment of the air quality standards by the earliest possible date. Approval of the Plan by the ARB for incorporation into the SIP is expected in early 1983; EPA approval is uncertain, since the Plan does not demonstrate attainment of the federal air quality standards by the deadlines.

It is hoped that implementation of the Plan will achieve compliance with federal and state standards by the year 2000 or shortly thereafter. Attempting to attain the standards by the 1987 final deadline would require drastic mitigation measures that appear to be almost impossible to implement (such as a 90 percent reduction in forecast petroleum refining, marketing, and extraction emissions, 100 percent use of non-reactive solvents and degreasers, and 80 percent fuel rationing). The approved 1982 Plan for later compliance will still require major changes in the South Coast Air Basin. The plan calls for both short-range and long-range tactics to control industrial, commercial, and vehicular sources of air pollution. The short-term measures consist of setting standards for currently unregulated smaller sources of pollution, and tightening controls on larger sources. The long-range control measures include use of alternatives to petroleum products, in addition to other measures.

Table 10-13 presents the air quality standards, allowable emissions to meet the standards, emissions for the baseline year (1979) and projected emissions for 1987 and 2000, required emission reductions in order to meet the standards, reductions achievable through the 1982 Plan, and the shortfall. The following paragraphs discuss potential use of methanol in both the short-term and long-term strategies.

The short-range control strategies outlined in the Plan are those that can be implemented before 1987. 135 strategies were considered reasonably available; of these 104 were well defined and quantifiable, while 31 were non-traditional and non-technological. Table 10-13 shows emission reductions achievable by 1987 and 2000, if all of the quantifiable measures are implemented. Air quality for all contaminants will improve over the next five years in terms of reducing peak concentrations or meeting some of the air quality standards, although the compliance deadlines will not be met. Implementation of all the recommended measures will accomplish the following:

Ozone: Reduction of the number of first and second stage ozone episodes. In the years 1978 through 1980, there were an average of 115 first-stage episode days and 21 second-stage episode days in the South Coast Air Basin. Modeling estimates indicate that implementation of all proposed reactive organic gas (ROG) and NO_x measures will reduce these violations to a range of 33-80 first-stage and 0-1 second-stage days in 1987, and 15-55 first-stage and zero second-stage episode days by the year 2000.

Nitrogen Dioxide: Attainment of federal standards by 1987 and the state standard by 2000.

Table 10-13. REQUIRED AND AVAILABLE EMISSION REDUCTIONS TO MEET AIR QUALITY STANDARDS

POLLUTANT	MOST STRINGENT AIR QUALITY STANDARD	ALLOWABLE BASINWIDE EMISSIONS (TONS/DAY)	EMISSIONS (TONS/DAY)			REQUIRED EMISSION REDUCTIONS (Tons/Day)		EMISSION REDUCTIONS AVAILABLE THROUGH AQMP (Tons/Day)		EXCESS (SHORTFALL) REDUCTIONS (Tons/Day)	
			1979	1987	2000	1987	2000	1987	2000	1987	2000
FEDERAL STANDARDS											
Reactive Organic Gas	0.12 ppm O_3 1-Hr Avg.	230	1535	1023	1087	793	857	267	486	(526)	(371)
Oxides of Nitrogen	0.053 ppm NO_2 Annual Avg.	898	1243	960	921	62	23	262	486	200	463
Carbon Monoxide	9.3 ppm CO 8-Hr Avg. (1 Violation/ Station-Yr)	2560[a]	7360[a]	5790[a]	5730[a]	3230[a]	3170[a]	2167[a]	4415[a]	(1063)	1245
Oxides of Sulfur	0.030 ppm SO_2 Annual Avg.	475	274	180	188	0	0	73	95	368	382
Particulate Matter	260 ug/m^3 TSP 24-Hr Avg.	256	613	618	694	362	438	27	55	(335)	(383)
Lead	1.5 ug/m^3 Lead 1/4 - year Avg.	4.17[b]	9.10[b]	3.52[b]	2.51[b]	0	0	0	0	0	0

Table 10-13. REQUIRED AND AVAILABLE EMISSION REDUCTIONS TO MEET AIR QUALITY STANDARDS (continued)

POLLUTANT	MOST STRINGENT AIR QUALITY STANDARD	ALLOWABLE BASINWIDE EMISSIONS (TONS/DAY)	EMISSIONS (TONS/DAY)			REQUIRED EMISSION REDUCTIONS (Tons/Day)		EMISSION REDUCTIONS AVAILABLE THROUGH AQMP (Tons/Day)		EXCESS (SHORTFALL) REDUCTIONS Tons/Day)	
			1979	1987	2000	1987	2000	1987	2000	1987	2000
STATE STANDARDS[c]											
Reactive Organic Gas	0.10 ppm O^3 1-Hr Avg.	100-200[d]	1535	1023	1087	823-923[d]	887-987[d]	267	486	(556-656)	(401-501)
Oxides of Nitrogen	0.25 ppm NO_2 1-Hr Avg.	572	1243	960	921	388	349	262	486	(126)	137
Oxides of Sulfur	25 ug/m^3 Sulfate 24-Hr Avg.	124	274	180	188	56	64	73	95	17	31
Particulate Matter	100 ug/m^3TSP 24-Hr Avg.	67	613	618	694	551	627	27	55	(524)	(572)
Lead	1.5 ug/m^3Lead 30-day/Avg.	3.19[b]	9.10[b]	3.52[b]	2.51[b]	0.33[b]	0	0	0	(0.33)	0

a. Average winter weekday emissions.
b. Motor vehicle emissions only. Stationary sources do not contribute to the maximum measured values.
c. Only for those state standards which are more stringent than the federal standards or for which no federal standards exist.
d. Reduction requirement uncertain due to uncertainty in background concentrations at low emission rates.

SOURCE: Reference 25.

Carbon Monoxide: Attainment of federal standards by 2000, while reducing the number of violations of state standards.

Sulfur Dioxide and Sulfates: Continued attainment of federal sulfur dioxide standards and reduction of state sulfate standard violations.

Total Suspended Particulates: Reduction of the number of violations of the current federal standard. Attainment of the standard if it is changed to include only inhalable particulates.

Total Oxidants: Reduction of total oxidants, including ozone, concentrations. (Some oxidants may have more severe health effects than ozone.) (Ref. 25)

Five basic types of short-term control measures were proposed: (1) stationary source controls, (2) transportation measures, (3) mobile technological controls, (4) energy conservation measures, and (5) land use measures. Two of the recommended control strategies, one for electrical generation and one for vehicle emission control, have potential methanol applications.

The electric generation emission control strategy (Ref. 34) consists of using methanol in electric utility gas turbines in order to reduce SO_2 emissions. Projected SO_2 reductions from this strategy are 0.20 tons/average day in 1987, and 0.20 tons/average day in 2000. The target date for implementation is 1986, but this is contingent upon the availability of low-cost methanol in large quantities. SCAQMD will not adopt a rule for this measure until there is assurance of such a supply. This measure does not appear to be a valuable use of methanol, since the South Coast Air Basin is already in compliance with the SO_2 standard and few future problems are anticipated.

The vehicle emission control strategy is to convert fleet vehicles in the SCAQMD to run on methanol fuel, in order to reduce emissions of reactive organic gases, NO_x, and CO. This measure would target approximately 16 percent of the light-duty vehicle fleet, or 1.36 million vehicles by 2000, and is designed to encourage the use of at least 85 percent methanol fuel. Potential emission reductions from this strategy are indicated in Table 10-14.

The SCAQMD feels that fleet vehicles are the most appropriate candidates for methanol conversion. According to SCAQMD, such conversions would not disrupt the existing petroleum retail distribution system, and would provide a smooth transition to increased use of methanol fuel. The target date for implementation of this strategy is 1984. However, several actions are needed to carry out this measure. SCAQMD feels that support from the U.S. Synthetic Fuels Corp. for coal-based methanol is necessary. The Clean Air Act must be amended to allow for limited exemptions from rules that control the introduction and use of new motor vehicle fuels, and exemptions from anti-tampering provisions. The state legislature could provide several incentives, such as passing legislation requiring sale of methanol at service stations, creation of regional methanol service station directories, and continued support for tax credit legislation for conversions beyond the 1991 deadline.

Table 10-14. METHANOL FLEET VEHICLE CONVERSION: EMISSION FORECAST AND REDUCTION

	1979	1987	2000
ROG Inventory (Ton/Avg. Day)	647	329	319
ROG Reduction (Ton/Avg. Day)		4.1	16.2
NO_x Inventory (Ton/Avg. Day)		279	231
NO_x Reduction (Ton/Avg. Day)	471	1.1	4.5
CO Inventory (Ton/Avg. Day)	4,673	3,331	3,211
CO Reduction (Ton/Avg. Day)		88.5	345.6

SOURCE: Ref. 34

The Plan's long-range control strategies are those which could lead to attainment of the ozone and CO standards, hopefully by the year 2000 or soon after. These strategies require lead time or further study before implementation; it is hoped that studies will be completed by 1987. Three broad categories of strategies appear to be the most promising for further reduction of reactive organic gases emissions after implementation of the short-term strategies: use of lower polluting alternative fuels, transportation and urban form changes, and technology advances for reduced emissions. The alternative fuel use category includes two measures with potential methanol applications.

One of the long-term measures is to use alternatively powered vehicles (such as methanol, electric, or natural gas cars). SCAQMD believes that limited quantities of the vehicles will become available in the near future; the objective of the long-range strategy is to promote widespread use of these vehicles until most of the cars in the South Coast Air Basin are powered by alternative fuels. However, methanol in vehicles must be used in conjunction with other strategies in order to reach attainment of the standards (Ref. 25).

The alternative fuel use by industrial sources strategy is to replace petroleum fuels with cleaner fuels, such as methanol or natural gas, in order to reduce emissions of organic gases. Because development tests are underway on various types and sizes of engines, useful data should be available in the near future to evaluate and quantify the possible benefits from the use of methanol. If a development program is started in the near future, SCAQMD feels that methanol could become available in sufficient quantities in the next 15 to 20 years and could have a significant impact on the air pollution problem.

Table 10-15 presents potential long-range reactive organic gas emission reduction from using one of the possible combinations of long-range control strategies.

The following is a set of actions which can be taken by the SCAQMD, the Southern California Association of Governments and local governments to facilitate the transition to alternative energy uses.

Table 10-15. POTENTIAL LONG-RANGE ROG EMISSION REDUCTIONS

STRATEGY/MEASURE	YEAR 2000 ROG EMISSION REDUCTIONS (tons/day)	
	WITHOUT SHORT-RANGE CONTROL MEASURES	WITH SHORT-RANGE CONTROL MEASURES
ENERGY USE		
Methanol Fueled Vehicles	127	47
Electric Powered Vehicles	110	40
Areawide Highway Electrification	41	15
Alternative Industrial Fuels	4	4
Petroleum Fuel Industry	116	83
TRANSPORTATION AND URBAN FORM		
Transportation System Design and Urban Form	50	18
Telecommunications	18	7
High Speed Trains	12	6
Less Than Anticipated Growth	38	21
Redirecting Growth		
TECHNOLOGY		
Non-Reactive Solvents	226	167
TOTAL NET ROG EMISSIONS REDUCTIONS*	450	371

*Total net emission reductions represent the amount of emission reduction after removing the overlaps between measures. This eliminates any double counting of emission reductions.

SOURCE: Ref. 25

- Study the feasibility of alternative energy use in the South Coast Air Basin. The studies should address the production potential of various alternative fuels, the design of a fuel distribution system, the compatibility of new fuel systems with existing systems and the costs of providing alternative fuels and the potential health effects of their use. These studies should be completed by 1985 so that actions can be taken to implement their recommendations.

- Study the economic, social and environmental impacts of a reduction in the Basin's petroleum fuel industry.

- Explore the potential alternative uses of lands currently being used by petroleum production facilities.

- Develop by 1986 a set of recommendations for state and federal tax incentives promoting alternative fuels. These tax incentives should encourage the production of alternative fuels and promote the use of alternative fuels.

- Institute regulatory actions by 1987 to facilitate alternative energy sources. These actions could include: streamlining the review process for alternative fuel development projects; encouraging or requiring the provision of alternative fuels to ensure public access to fuels; and allowing trading of emission offsets obtained through early conversion to alternative fuels.

- Conduct demonstration projects showing the feasibility of alternative fuels. These projects, which can be begun immediately, could include methanol and electric car demonstrations and support of private sector projects.

The state ARB has also devised a possible long-range mobile source control strategy for the South Coast Air Basin for reduction of hydrocarbon, CO, and NO_x emissions, targeted for the year 2000. Components of the strategy include reduction of excess emissions from regulated sources, tightening of standards for regulated sources, adoption of standards for unregulated sources, and replacement of portions of the vehicle fleet with advanced low emissions technology vehicles (Ref. 29). ARB has projected that if 10 percent of the passenger cars were converted to methanol by the projected 1987 implementation date, year 2000 hydrocarbon emissions would be reduced by 3 tons/day, CO emissions would be reduced by 57 tons/day, and NO_x emissions would be reduced by 2 tons/day.

Methanol appears to have greater potential for control of mobile source emissions than for control of stationary source emissions in the South Coast Air Basin. Pollutants from transportation sources are so significant that ARB believes that much more emphasis must be placed on transportation control measures during the next several years.

Methanol-fueled vehicles have the potential for substantially decreasing exhaust emissions and evaporative emissions that occur with gasoline-fueled vehicles. Some results of preliminary road and lab tests by the California Energy Commission are presented in Table 10-16. Unburned methanol is also

Table 10-16. 1982 CALIFORNIA EMISSION STANDARD VS 1982 VW RABBIT METHANOL EMISSIONS (Grams Per Mile)

	HC	CO	NO_x
1982 California Emission Standard	0.41	7.00	0.40
1982 VW Rabbit Methanol Emissions	0.12	0.80	0.32
Differences	0.29	6.20	0.08
Percentage Change	70.73%	88.57%	20.00%

SOURCE: Ref. 35.

present in the exhaust, but these emissions are essentially unreactive. Aldehyde emissions from methanol vehicles are highly reactive and may contribute directly to photochemical smog formation, but aldehyde emissions can be substantially reduced by present control technology (Ref. 34).

SCAQMD is not optimistic concerning the use of methanol/gasoline blends, and prefers the option of converting portions of the light-duty vehicle fleet to methanol fuel (Ref. 16).

Stationary applications of methanol fuel use do not appear to be stressed in the proposed control strategies. As a combustion fuel, methanol has more potential for lowering NO_x and CO emissions than fuel oil, and virtually no emissions of unburned hydrocarbons, SO_2, or particulates. As a gas turbine fuel, methanol appears to have advantages over distillate and natural gas, with potential for lowered NO_x, CO, hydrocarbon, and particulate emissions. Use of methanol in turbines for SO_2 reduction was recommended as a short-term strategy, but this may not be methanol's most advantageous use. The stringent new source review rule for new and modified stationary sources of pollution, recently adopted by SCAQMD (Ref.37) may provide more incentives for the use of a lower polluting fuel such as methanol to reduce emissions. However, use of methanol in stationary applications for offsets and emissions banking is unclear.

G. CONCLUSIONS

There are several priority environmental, health and safety concerns associated with large-scale use of methanol as a fuel in California. An overview of the issues indicates that the major adverse impacts will be associated with resource extraction, especially if western coal is the preferred feedstock, and methanol production from feedstock gasification. End use of methanol as a transportation or utility fuel results in overall positive impacts

on air quality, but some potential health and safety risks may occur. The major concerns can be summarized as follows:

(1) Strip mining of western coal for methanol feedstocks can result in irreparable loss of potentially productive land due to reclamation difficulty in arid and semiarid areas.

(2) Methanol production facilities require large quantities of water; this may place severe constraints on plant siting in many areas of the West.

(3) Little data exist on the characteristics and compositions of gasification waste streams, particularly in terms of potentially toxic, hazardous, or carginogenic organic constituents and trace elements. In addition, the effects of these potentially harmful substances on humans is poorly understood in many cases.

(4) Potential occupational health and safety hazards associated with large gasifiation/methanol production facilities are not well known.

(5) Large-scale use of methanol as a fuel may expose service personnel and the public to little-known risks of low-level, chronic methanol exposure. In addition, public education and appropriate safety precautions are needed to reduce accidental or intentional ingestion.

Easing of environmental regulations by the current Administration may result in lessening of constraints on coal mining and plant siting, but at the same time may reduce incentives for using methanol. California's environmental regulations, however, are likely to remain more stringent than EPA's. It must be kept in mind that environmentally damaging substances associated with the feedstocks will have to be dealt with at some point in the energy system. However, converting fossil fuel feedstocks to methanol via gasification may result in easier removal and control of environmentally harmful substances than combustion of the fossil fuels.

H. REFERENCES

1. U.S. Department of Energy, Environmental Analysis of Synthetic Liquid Fuels, DOE/EV-0044, 1979.

2. SRI International, Environmentally Based Siting Assessment for Synthetic Liquid Fuels Facilities, DOE/EV-10287, prepared for the U.S. Department of Energy, 1980.

3. Petrie, T. W., W. J. Rhodes, and G. C. Page, Environmental Aspects of Coal Gasification and Liquefaction Processes, paper presented at A.I.Ch.E. Symposium on Environmental Assessment of Solid Fossil Fuel Processes: Part I, Nov. 12-16, 1978.

4. U.S. Department of Energy, Environmental Readiness Document: Coal Gasification, Commercialization Phase III Planning, DOE/ERD-0012, 1978.

5. U.S. Department of Energy, Synthetic Fuels and the Environment: An Environmental and Regulatory Impacts Analysis, Review Draft, 1980.

6. Electric Power Research Institute, Coal-to-Methanol: An Engineering Evaluation of Texaco Gasification and ICI Methanol Synthetic Route, EPRI-AP-1962, 1981.

7. Gangwal, S. K., J. G. Cleland, and R. S. Truesdale, Evaluation of Relative Environmental Hazards from a Coal Gasifier, Industrial Environmental Research Laboratory, U.S. Environmental Protection Agency, EPA-600/57-81-100, 1981.

8. ICF, Inc., Methanol from Coal: Prospects and Performance as a Fuel and as a Feedstock, prepared for the National Alcohol Fuels Commission, 1980.

9. Muzio, L. J., and J. K. Arand, Utility Boiler Repowering with Methanol: Effect on NO_x Emissions, prepared by KVB, Inc., for Conoco Coal Development Co., 1981.

10. Ginevan, M.E., et al., Health and Environmental Effects for a High-Btu Coal Gasification Industry-1981, Argonne National Laboratory, U.S. Department of Energy, 1981.

11. Ghassemi, M., R. Iyer, R. Scofield, and J. McSorley, "Environmental Effects of Synfuel Use." Environmental Science and Technology 15:8, pp. 866-973, August 1981.

12. Radian Corporation, Assessment of Advanced Coal-Based Technologies for Use in California, California Energy Commission Report P300-80-036, 1980.

13. Badger Plants, Inc., Conceptual Design of a Coal-to-Methanol-to-Gasoline Commercial Plant: Volume III, Environmental, Second Interim Final Report, prepared for the U.S. Department of Energy, 1979.

14. SRI International, Synthetic Liquid Fuels Development: Assessment of Critical Factors, prepared for the U.S. Energy Research and Development Administration, ERDA 76-129/1, 2, 1976.

15. Bentz, E. J.. and E. J. Salmon, Synthetic Fuels Technology Overview with Health and Environmental Impacts, Ann Arbor Science Publishers, Inc., Ann Arbor, Michigan, 1981.

16. Sammons, D., The Synfuels Plant Siting Guide: A State-by-State Analysis, McGraw-Hill Publications Co., New York, 1981.

17. Spofford, W. O., Jr., A. L. Parker, and A. V. Kneese, eds., Energy Development in the Southwest, Research Paper R-18, Resources for the Future, Washington, DC, 1980.

18. 1981 Keystone Coal Industry Manual, Mining Information Services, McGraw-Hill Publications Co., New York, 1981.

19. Booz, Allen, and Hamilton, Inc., The Socioeconomic Impacts of Coal-to-Methanol Plants in Wyoming, prepared for the U.S. Department of Energy, 1982.

20. Adelman, H. G., P. N. D'Eliscu, and R. K. Pefley, Human Health, Safety, and the Environmental Consequences of Use of Alcohols, prepared for the National Alcohol Fuels Commission, 1981.

21. Moriarty, A. J., "Toxicological Aspects of Alcohol Fuel Utilization," Proceedings of the International Symposium on Alcohol Fuel Technology: Methanol and Ethanol, November 21-23, 1977, published by the U.S. Department of Energy, 1978.

22. Graham, H., et al., "Methanol and Ethanol - Environmental, Health, and Safety Issues," Proceedings of the International Symposium on Alcohol Fuel Technology: Methanol and Ethanol, November 21-23, 1977, published by the U.S. Department of Energy, 1978.

23. Wimer, R. L., M. A. Adams, and D. M. Jurich, Characterization of Seven United States Coal Regions, Kaiser Engineers, Inc., and TRW, Inc., for the U.S. Department of Energy, February 1981.

24. California Air Resources Board, Forward to the State of California's 1979 State Implementation Plan Amendments in Response to the Clean Air Act Amendments of 1977, July 1979.

25. South Coast Air Quality Management District and Southern California Association of Governments, Draft Air Quality Management Plan: 1982 Revision, August 1982.

26. California Air Resources Board. "Chapter 4: California Air Quality Control Strategies, Revision to State of California Implementation Plan for the Attainment and Maintenance of Ambient Air Quality Standards, April 1979.

27. California Air Resources Board, Alcohols as Motor Vehicle Fuels in California, Draft Report, April 1982.

28. California Air Resources Board, "Notice of Executive Office Public Hearing to Consider Adoption of Title 13, California Administrative Code, Section 2031 and the Test Procedures, Incorporated Therein, Regarding California Exhaust Emission Standards and Test Procedures for Systems Designed to Convert Motor Vehicles to Use Alcohol or Alcohol/Gasoline Fuels, and Section 2177, Regarding Guidelines for Issuance of Certificates of Compliance," Mail Out #82-27, 1982.

29. California Air Resources Board, Long-Range Plan for Reducing Emissions from Mobile Sources, presentation package, October 14, 1982, revised October 19, 1982.

30. California Air Resources Board, New Vehicle Standards Summary, September 30, 1982.

31. California Air Resources Board, Bulletin, 2:10, August-September 1982.

32. California Air Resources Board, California Air Pollution Control Laws, 1982.

33. Association of Bay Area Governments, Bay Area Air Quality Management District, and Metropolitan Transportation Commission, Draft 1982 Bay Area Air Quality Plan, July 1982.

34. South Coast Air Quality Management District and Southern California Association of Governments, Draft Air Quality Management Plan, 1982 Revision: Appendix No. VII-A, Short Range Tactics for the South Coast Air Basin, August 1982.

35. South Coast Air Quality Management District and Southern California Association of Governments, Draft Air Quality Management Plan, 1982 Revision: Appendix No. VIII-D, Alternative Vehicle Fuels, August 1982.

36. South Coast Air Quality Management District and Southern California Association of Governments, Draft Air Quality Management Plan, 1982 Revision: Appendix No. VIII-A, Energy Use and Alternative Fuels, August 1982.

37. South Coast Air Quality Management District, Regulation XIII, as amended September 10, 1982.

ADDENDUM

ENVIRONMENTAL AND REGULATORY CONSTRAINTS

ENVIRONMENTAL STANDARDS FOR NEW COAL-FIRED POWER PLANTS

I. AIR

A. CONVENTIONAL PULVERIZED COAL

New Source Performance Standards have been issued by EPA for new, modified, and reconstructed electric utility steam generating units capable of firing >73 MW heat input of fossil fuel. Limits are imposed on SO_2, NO_x and particulates emissions; new units are required to use best demonstrated technological systems of continuous emission reduction to satisfy the requirements of the 1977 Clean Air Act Amendments. Standards applicable to conventional coal-fired plants are set forth in Table 1.

Table 1. AN NSPS: COAL-FIRED UTILITY STEAM GENERATING UNITS

Pollutant	Standard
SO_2	1. SO_2 emissions of > 0.60 lb/MBtu heat input: 90% reduction in potential emissions 2. SO_2 emissions < 0.60 lb/MBtu: 70% reduction in potential emissions 3. 1.2 lb/MBtu ceiling
NO_x	Varies according to fuel type. 1. Subbituminous coal: >0.50 lb/MBtu heat input 2. Any fuel with <25% (weight) lignite from N. Dakota, S. Dakota, or Montana: 0.80 lb/MBtu from combustion in a slag tap furnace 3. Fuel with >25% coal refuse: exempt from NO_x standards 4. Other coals not specified above: 0.60 lb/MBtu
Particulates	0.03 lb/MBtu heat input
Initial full-scale demonstrations of certain technologies are subject to less stringent standards (case-by-case basis).	

B. INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

It is not clear if existing and proposed air quality regulations applicable to gas turbines and large coal-fired utility steam stations will be applicable to IGCC plants. Currently, for electric utility combined-cycle

plants, the NSPS as defined in Section A. 1-a. are applicable to steam generator emissions resulting from fossil fuel fired to the steam generator with >73 MW heat input, exclusive of the heat input and electrical power contribution of the gas turbine. Combined-cycle gas turbines that use only turbine exhaust gas to provide heat to a steam generator (waste heat boiler), and that are fired with 73 MW of fossil fuel, are not covered by the NSPS for steam electric utilities.

NSPS have been promulgated limiting SO_2 and NO_x for all stationary gas turbines with a heat input at peak load of >10.7 gigajoules /hr, based on the lower heating value of the fuel. These standards are applicable to any gas turbine portion of a combined-cycle steam/electric generating system. The efficiency factor must be based on gas turbine efficiency itself, not the over-all efficiency of a gas turbine combined with other equipment. NSPS for combined-cycle systems are summarized in Table 2. Fuel-bound nitrogen allowances have been proposed for gas turbines. These are summarized in Table 3.

Since IGCC cleanup processes are designed to remove fuel-bound nitrogen compounds in addition to sulfur and particulates, these allowances will most likely not apply to IGCC plants.

Although the status of EPA regulation of IGCC emissions is unclear, states may regulate particulates, SO_2 and NO_x emissions from IGCC systems.

C. FLUIDIZED-BED COMBUSTION (FBC)

New FBC facilities are subject to the SO_2, particulates, and NO_x NSPS for fossil-fired utility steam generating units as described in Section I(A). However, the 90% reduction required for SO_2 may be reduced to 85% reduction for full-scale commercial demonstrations. The gas turbines of combined-cycle FBC plants are subject to the NSPS for gas turbines and the constraints established for the desired turbine performance described in Section I(B).

II. WATER

A. CONVENTIONAL PULVERIZED COAL

EPA has promulgated final regulations limiting aqueous pollutant discharges from new coal-fired steam electric power plants. However, EPA is currently proposing to revise these regulations to include best available technology (BAT) limitations on some toxic and other chemical pollutants in certain waste streams. Restrictions on thermal pollution from power plants have been remanded; EPA is not proposing regulations for thermal discharges at this time.

EPA has proposed effluent guidelines and standards for the following liquid waste streams from steam electric power plants:

1. Once-through cooling water

Table 2. NSPS: Combined Cycle Systems

GAS TURBINE SIZE AND USAGE	NO_x EMISSION LIMIT[1]	APPLICABILITY DATE FOR NO_x	SO_2 EMISSION LIMIT	APPLICABILITY DATE FOR SO_2
Less than 10.7 gigajoules/hour (all uses)	None	Standard does not apply	None	Standard does not apply
Between 10.7 and 107.2 gigajoules/hour (all uses)	150 ppm	October 3, 1982	150 ppm or be a fuel with less than 0.8% sulfur	October 3, 1977
Greater than or equal to 107.2 gigajoules/hour:				
1. Gas and oil transportation or production not located in an MSA	150 ppm	October 3, 1977	Same as above	October 3, 1977
2. Gas and oil transportation or production located in an MSA	75 ppm	October 3, 1977	Same as above	October 3, 1977
3. All other uses	75 ppm	October 3, 1977	Same as above	October 3, 1977
Emergency standby, firefighting, military (except for garrison facility), military training, and research and development turbines	None	Standard does not apply	Same as above	October 3, 1977

[1] NO_x emission limit adjusted upward for gas turbines with thermal efficiencies > 25% and for gas turbines firing fuels with a nitrogen content of more than 0.015 weight %. Measured NO_x emissions adjusted to ISO conditions in determining compliance with the NO_x emission limit.

STEAM GENERATORS	
Fired with turbine exhaust gas and < 73 MW of fossil fuel	Emissions not covered by NSPS
Fired with turbine exhaust gas and >73 MW of fossil fuel	Emissions resulting from firing of >73 MW of fossil fuel subject to NSPS for steam/electric utilities.

Table 3. FUEL-BOUND NITROGEN ALLOWANCES FOR GAS TURBINES

Fuel-Bound Nitrogen (% by Weight)	NOx % by Volume
$N < 0.015$	0
$0.015 < N < 0.1$	0.04 (N)
$0.1 < N < 0.25$	0.004 + 0.0067 (N-0.1)
$N < 0.25$	0.005

2. Cooling tower blowdown
3. Fly ash transport water
4. Bottom ash transport water
5. Low volume wastes, including boiler blowdown
6. Metal cleaning wastes
7. Area runoff

Final and proposed NSPS discharging to surface waters and pretreatment standards for new sources (PSNS) discharging to publicly owned treatment works are outlined in Table 4.

B. INTEGRATED GASIFICATION COMBINED-CYCLE/FLUIDIZED BED COMBUSTION

Effluent guidelines and standards for new IGCC and FBC facilities have not yet been proposed, and are not likely to be proposed for the next two or three years. Permit writers for these facilities will be guided by NSPS for the most similar point source, which will most likely be the NSPS for steam electric generators defined in II(A).

III. SOLID WASTE

A. CONVENTIONAL PULVERIZED COAL

Solid wastes produced in conventional coal-burning steam electric plants, including fly ash waste, bottom ash waste, slag waste, and flue gas emission control waste generated from coal and other fossil fuel combustion are not defined as hazardous wastes by EPA. Disposal of these solid wastes is still subject to 1976 RCRA disposal requirements and 1979 guidelines for solid waste disposal in sanitary landfills (RCRA Sections 4004 and 1008).

Table 4. EFFLUENT GUIDELINES AND STANDARDS: NSPS AND PSNS FOR STEAM ELECTRIC POWER PLANTS

STANDARDS	ONCE-THROUGH COOLING WATER	COOLING TOWER BLOWDOWN	FLY ASH TRANSPORT WATER	BOTTOM ASH TRANSPORT WATER	LOW VOLUME WASTES (Including Boiler Blowdown)	METAL CLEANING WASTES	COALPILE AND CHEMICAL HANDLING AND RUNOFF
NSPS	*No discharge of total residual chlorine (TRC) unless need is demonstrated through chlorine minimization studies *If allowed, TRC not to exceed 0.14 mg/l *TRC discharges to be limited to 2 hrs/day unless longer periods are demonstrated to be necessary	*TRC: 0.14 mg/l maximum *No discharge of cooling tower & condensor maintenance chemicals that contain any of the 129 priority pollutants ph: 6.0-9.0	*No discharge of fly ash transport water	TSS: 100.0 mg/l (1-day max.) 30.0 mg/l (30-day av.) Oil & grease: 20 mg/l (1-day max.) 15.0 mg/l (30-day av.) pH: 6.0-9.0 *Withdraw current NSPS of 20 x recycle	TSS, oil & grease: same as bottom ash transport water pH: 6.0-9.0 *Delete scrubber blowdown waste limitations	TSS, oil & grease: same as bottom ash transport water Copper, total: 1.0 mg/l (1-day max.) 1.0 mg/l (30-day av.) Iron, total: 1.0 mg/l (1-day max.) 1.0 mg/l (30-day av.) pH: 6.0-9.0	*TSS: 50 mg/l max for any time
PSNS	No limitations	TRC: No limit No discharge of 129 priority pollutants	*No discharge of fly ash transport water	No limitations	No limitations	*Copper, total: 1.0 mg/l	No limitations

Note: No discharge of polychlorinated biphenyls (PCB's) is allowed

*Proposed new standard (45 Fed. Reg. 68328, October 14, 1980).

B. INTEGRATED GASIFICATION/COMBINED-CYCLE

Solid wastes generated by coal gasification are not currently classified as hazardous by EPA and are excluded from any hazardous designation under existing EPA rules. Elemental sulfur produced by IGCC processes can be sold. Slag and other solid wastes generated by IGCC processes can be disposed of under solid waste guidelines, as mentioned in III(A). Some IGCC slags may be classified as hazardous under individual state laws, and must be disposed of accordingly.

C. FLUIDIZED BED COMBUSTION

Currently, FBC solid wastes are considered non-hazardous and can be disposed of in sanitary landfills using approved practices, as mentioned in III(A). FBC solid residue may be a candidate for inclusion in EPA's special waste category under RCRA. Proposed regulations governing special wastes are due from EPA in early 1982.

IV. OTHER

Toxic Substances. Currently, none of the components of by-product streams from the three processes contain significant toxic substances as defined by EPA under TSCA. Some concern has been raised over the presence of phenols in by-product streams from coal gasification; EPA is currently studying the issue. Synfuels facilities will be subject to Section 5 of TSCA, in which EPA must be notified prior to manufacturing a new chemical substance for commercial purposes.

Hazardous Air Pollutants. EPA has the authority to define and regulate hazardous air pollutants under Section 112 of the Clean Air Act. Hazardous air pollutant standards currently exist for:

1. Asbestos
2. Beryllium
3. Mercury
4. Vinyl chloride

Listed as hazardous, but no standards yet:

1. Benzene
2. Arsenic
3. Radionuclides

Health assesments completed or nearly completed on:

1. Coke emissions

2. Acrylonnitrile

3. Methyl chloroform

4. Methylene chloride

5. Trifluorochloroethane

6. Perchloroethylene

7. Trichloroethylene

8. Chloroform

9. Vinylidene

10. Chromium

11. Chloride

12. Formaldehyde

13. Nickel

14. Ethylene dichloride

15. Dioxin

None of the emissions from the three processes are expected to be designated as hazardous air pollutants.

Acid Rain Control. Several acid rain control bills have been introduced into the Senate and House, and some form of acid rain legislation in 1982 is highly probable. New and existing large electric power utilities will be the most affected. Potential plans for control can be summarized as follows:

1. A 5-million ton two-phase reduction in SO_2 and NO_x from a 23-state corridor by 1990, with the states given the responsibility to come up with reduction plans or face a mandatory federal emissions reduction plan. Trading between NO_x and SO_2 would be allowed.

2. A 10-million ton reduction in SO_2 from 31 eastern states over a ten-year period.

3. An 8.2 million ton or 36% reduction in SO_2 from a 31-state region by 1991; no specific target for NO_x. Tradeoffs between states, and in SO_2-NO_x emissions, would be allowed.

The most likely outcome will be a compromise among the proposed changes.

Uncertainties

1. Visibility protection: Adoption of a secondary fine particulate standard is not likely. Visibility protection may wait until acid rain control strategy is revised.

2. NSPS for synthetic fuel facilities: EPA is still gathering data prior to standard development. Not likely to be developed for at least several years.

3. NSPS for fossil fuel-fired steam electric utilities: Potential relaxation of SO_2 percentage removal requirement.

4. NAAQS primary particulate standard: 1982 EPA proposed revisions may relax present limits by up to 50%.

5. Stringent NO_x standards may limit atmospheric fluidized bed combustion (AFBC) dense-bed boiler applications.

6. Classification of FBC solid wastes under RCRA.

7. Potential acid rain control amendments to the Clean Air Act.

8. Characterization and classification of coal gasification waste stream constituents.

CHAPTER ELEVEN

BIBLIOGRAPHY

Abens, S., et al., 1.5 kW Methanol Fuel Cell Power Plant, Final Technical Report for U.S. Army, April 1978.

Abshire, A. D., "Ethanol, Methanol and the Higher Alcohols," Alcohol as an Octane Enhancer in the 80s Conference, San Antonio, Texas, March 24-25, 1982.

Acurex Corporation, Alternate Fuel Strategies for Stationary and Mobile Engines: Evaluation of Clean Coal Fuels, Volume III, July 1981.

Acurex Corporation, "Clean Coal Fuels: Alternate Fuel Strategies for Stationary and Mobile Engines," Vol. VII: An Assessment of Methanol-Fueled Heavy-Duty Engines, Draft Report #FR-82-109/EE, April 1982.

Adelman, H. G., Browning, L. H., and Pefley, R. K., "Predicted Exhaust Emissions from a Methanol and Jet Fueled Gas Turbine Combustor," AIAA J., Vol. 14, No. 6, June 1976.

Adelman, H. G., D'Eliscu, P. N., and Pefley, R. K., Human Health, Safety, and Environmental Consequences of Use of Alcohols, prepared for the National Alcohol Fuels Commission, 1981.

A. D. Little, Inc., California Clean Fuels Study, ERC&DC, Air Resources Board, Cambridge, Mass., April 1978.

Allsup, J. R., Experimental Results Using Methanol/Gasoline Blends as Automotive Engine Fuel, Bartlesville Energy Research Center Report, RI-76-15, January 1977.

Arthur Young and Co., Analysis of Financial Incentives for Biomass Energy, Sacramento, January 1981.

Association of Bay Area Government, Bay Area Air Quality Management District, and Metropolitan Transportation Commission, Draft 1982 Bay Area Air Quality Plans, July 1982.

Atkinson, R., et al., Advan. Photochem., No. 11, p. 375, 1979.

Atkinson, R., Perry, R. A., and Pitts, J. N., Jr., J. Chem. Phys. No. 66, p. 1197, 1977.

Atlantic Richfield Company, Atlantic Richfield Company Clean Air Act Section 211(f) Waiver Application, Los Angeles, Calif., April 17, 1981.

Atlantic Richfield Company, Application to Environmental Protection Agency for Waiver for Oxygenated Fuels under the Clean Air Act Section 206, 1981.

Atlas of California, Academic Book Center, Portland, Oregon, 1979.

Aude, T. C., and Chapman, J. P., "Coal/Methanol Slurry Pipelines," Proceedings of the 5th International Technical Conference on Slurry Transportation, pp. 106-114, March 1980.

Average Yearly Mileage Figures for Fleet Automobile Vehicles, Letter from W. Brooks and D. Naughton of BNL to Phillip Patterson of DOE, October 20, 1977

Badger Plants, Inc., Aspects of Commercializing Coal-Derived Methanol Fuels in the United States: 1985 to 2000, Market Evaluation, Vol. 1 & 2, prepared for the U.S. DOE, FE-2416-44, March, 1980.

Badger Plants Inc., Conceptual Design of a Coal-to-Methanol-Gasoline Commercial Plant, FE-2416-43, Cambridge, Massachusetts, March 1979.

Badger Plants, Inc., Conceptual Design of a Coal-to-Methanol-to-Gasoline Commercial Plant: Volume III, Environmental, Second Interim Final Report, prepared for the U.S. Department of Energy, 1979.

Baker, R. E., and Daby, E. E., "Engine Mapping Methodology," SAE Paper No. 770077, presented at International Automotive Engineering Congress and Exposition, Detroit, Mich., February 28-March 4, 1977.

Baldwin, A. C., Barker, T. R., Golden, D. M., and Hendry, D. G., J. Phys. Chem. No. 81, p. 2483, 1977.

Bandel, W., and Ventura, L. M., "Problems in Adapting Ethanol Fuels to the Requirements of Diesel Engines," Paper No. B. 52, Session B. VII, Fourth International Symposium on Alcohol Fuels Technology, Oct. 5-8, 1980.

Banks, W. F., "Economics of Non-Water Coal Slurry Systems," Proceedings of the Fourth International Technical Conference on Slurry Transportation, pp. 165-170, March 1979.

Barbieri, R. H., et al., Process Heat in California, JPL Publication 78-33, March 1978.

Bechtel Corp., Economic Feasibility of Synthetic Fuel Project, San Francisco, California, November 1981.

Bechtold, R. L., "Performance, Emissions, and Fuel Consumption of the White L-163-S Stratified-Charge Engine Using Various Fuels," Society of Automotive Engineers, (Passenger Car Meeting) Troy Hilton, Troy Mich., June 5-9, 1978.

Bechtold, R., and Pullman, J. B., "Driving Cycle Economy, Emissions and Photochemical Reactivity Using Alcohol Fuels and Gasoline," SAE Paper No. 800260, February 1980.

Bentz, E. J., and Salmon, E. J., Synthetic Fuels Technology Overview with Health and Environmental Impacts, Ann Arbor Science Publishers, Inc., Ann Arbor, Michigan, 1981.

Black, F. M., High, L. E., and Lang, J. M., "Composition of Automobile Evaporative and Tailpipe Hydrocarbon Emissions," J. Air Pollution Control Assoc. No. 30, p. 11, November 1980.

Bonner & Moore Associates, Inc., The 1985 California Oil Scenario Study, performed for an ad hoc group of California industry and government representatives, March 20, 1980.

Booz, Allen & Hamilton Inc., Projected Heavy Crude Refining in California and Options for Disposal of Residual Oil Surplus, California Energy Commission, June 1981.

Booz, Allen, and Hamilton, Inc., The Socioeconomic Impacts of Coal-to-Methanol Plants in Wyoming, prepared for the U.S. Department of Energy, 1982.

Brinkman, N., "Effect of Compression Ratio on Exhaust Emissions and Performance of a Methanol-Fueled Single-Cylinder Engine," SAE Paper No. 770791, 1977.

Brinkman, N., "Vehicle Evaluation of Neat Methanol - Compromises Among Exhaust Emissions, Fuel Economy, and Driveability," Energy Research No. 3, pp. 243-274, 1979.

Brinkman, N., et al., "Exhaust Emissions, Fuel Economy, and Driveability of Vehicles Fueled with Alcohol Gasoline Blends," SAE Paper 750120, February 1975.

Browning, L. H. and Pefley, R. K., Computer-Predicted Compression Ratio Effects on NO_x Emissions from a Methanol-Fueled Engine, Dept. of Mechanical Engineering, University of Santa Clara, California, 1978.

Broyles, A. R., "Methanol, Methanol, Methanol," Chemical Week, Coal Week, and Coal Week International, New York, Dec. 1-2, 1981.

Bufalini, J. J., Walter, T. A., and Bufalini, M. M., "Ozone Formation Potential of Organic Compounds," Environ. Sci and Technol. Vol. 10, No. 9, pp. 908-912, 1976.

California Air Resources Board, Alcohols as Motor Vehicle Fuels in California, Draft Report, April 1982.

California Air Resources Board, California Air Pollution Control Laws, 1982.

California Air Resources Board, California Air Quality Control Strategies - Revision to State of California Implementation Plan for the Attainment and Maintenance of Ambient Air Quality Standards, Chapter 4, April 1979.

California Air Resources Board, Engineering Evaluation Section, Mobile Source Control Division, Alcohol-Fueled Fleet Test Program, Project 3T8001, Second Interim Report, July 1981.

California Air Resources Board, Engineering Evaluation Section, Mobile Source Control Division, Alcohol-Fueled Fleet Test Program, Project 3T8001, Third Interim Report, October 1981.

California Air Resources Board, Foreword to the State of California's 1979 State Implementation Plan Amendments in Response to the Clean Air Act Amendments of 1977, July 1979.

California Air Resources Board, Long-Range Plan for Reducing Emissions from Mobile Sources, presentation package, October 14, 1982, revised October 19, 1982.

California Air Resources Board, New Vehicle Standards Summary, September 30, 1982.

California Air Resources Board, Notice of Executive Office Public Hearing to Consider Adoption of Title 13, California Administrative Code, Section 2031 and the Test Procedures, Incorporated Therein, Regarding California Exhaust Emission Standards and Test Procedures for Systems Designed to Convert Motor Vehicles to Use Alcohol or Alcohol/Gasoline Fuels, and Section 2177, Regarding Guidelines for Issuance of Certificates of Compliance, Mail Out #82-27, 1982.

California Air Resources Board, Stationary Source Control Division, Supplement to Procedure and Basis for Estimating On-Road Motor Vehicle Emissions, June 1981.

California Air Resources Board, Technical Services Division, Procedure and Basis for Estimating On-road Motor Vehicle Emissions, January 1980.

California Air Resources Board, Vehicle Emissions Control Division, Final Report of the Light-Duty Vehicle Surveillance Test Program, Second Series, February 1980.

California Air Resources Board, Vol. 2, No. 10, Bulletin, August-September 1982.

California Energy Commission, Fuel Price and Supply Projections, 1980-2000, Staff Report, June 1980.

California Energy Commission, Quarterly Fuel and Energy Summary, Vol. 6, No. 4, 1980.

California Energy Commission, Renewables and Alternative Technologies Symposium, Staff Draft Report, September 1980.

California Energy Commission, Senate Bill 620: Alcohol Fleet Test Program, Staff Report CEC 920-6811, December 1981.

California Energy Commission, 1981 Biennial Report.

Carlson, B., (DuPont), Methanol Outlook, presented at Chemical Marketing Research Assoc. meeting in New York, May 4-6, 1981.

Carlson, C. R., The SYSGEN User Package, JPL Publication 81-47, DOE/JPL-1060-47, March 1981.

Carter, W. P., Darnall, K. R., Graham, R. A., Winer, A. M., and Pitts, J. N., Jr., J. Phys. Chem., No. 83, p. 2305, 1979.

Cass, G. R., Boone, P. M., and Macias, E. S., "Emissions and Air Quality Relationships for Atmospheric Carbon Particles in Los Angeles," Wolff, G. T. and Klimisch, R. L. (Eds.) Particulate Carbon: Atmospheric Life Cycle, Plenum Publishing Corporation, 1982.

Cass, G. R., "On the Relationship Between Sulfate Air Quality and Visibility with Examples in Los Angeles," Atm. Environ. No. 113, pp. 1069-1084, 1979.

Cass, Hahn and Noll, Implementing Tradable Emissions Permits for Sulfur Oxides in the South Coast Air Basin, Environmental Quality Laboratory, California Institute of Technology, June 30, 1982.

Chase, J. D., and Galvez, B. B., "Maximize Blend Ethers with MTBE and TAME," Hydrocarbon Processing, March 1981.

Chigier, N., (Ed.), Energy and Combustion Science, Student Edition 1, Pergamon Press, London, 1979.

Choma, M. A., Havstad, P. V., Simko, A. O., and Stockhausen, W. F., "Fuel Tolerance Tests With the Ford Proco Engine," SAE Paper 810439, 1981.

Chow, T. K., and Stanbridge, D. W., Screening Evaluations: Synthetic Liquid Fuel Manufacture, EPRI AF-523, Ralph M. Parsons Co., Pasadena, California, August 1977.

Chuang, Kang-Chun, The Pipeline Transmission of Coal and Coal-Derived Fuel Gases, Chemical Engineering Thesis for West Virginia University, 1976.

Cichanowicz, J. E., Heap, M. P., McMillan, R. E., and Zoldak, F. D., Pollectant Control Techniques For Package Boilers: Phase I Hardware Modifications and Alternate Fuels, Draft Report, EPA Contract 68-02-1498, February 1977.

Cleveland, W. S., Graedel, T. E., and Kleiner, B., Atm. Environ., No. 11, p. 357, 1976.

Congress of the United States, Office of Technology Assessment, A Technology Assessment of Coal Slurry Pipelines, March 1978.

Congress of the United States, Office of Technology Assessment, The Direct Use of Coal: Prospects and Problems of Production and Combustion, April 1979.

Conklin, M. H., Cass, G. R., Chu, L-C., and Macias, E. S., "Wintertime Carbonaceous Aerosols in Los Angeles, The Role of Elemental Carbon," in Macias, E. S., and Hopke, P., (Eds.) Chemical Composition of Atmospheric Aerosols; Source/Air Quality Relationships, American Chemical Society, Washington, D.C., 1981.

Conoco, The Production, Economics, and Marketing of Methanol, No. 6, presented to General Motors Corp., March-April 1982.

Cowling, E. B., "Acid Precipitation in Historical Perspective," 16 Environ. Sci. and Technol., Vol. 16, No. 2, 1982.

Data Resources, Inc., Energy Review, Spring 1982.

Dodge, M. C., and Whitten, G. Z., Aldehydes and Photochemical Smog, presented to the Division of Environmental Chemistry, American Chemical Society, New York, April 1976.

Dowdy, M. W., Comparisons and Future Potential in Conventional Engine Technology, Volume III, Jet Propulsion Laboratory, May 21, 1981.

Duhl, R. W., and Boylan, R. W., Use of Methanol as a Boiler Fuel, paper presented at the Swedish Academy of Engineering Sciences, Stockholm, Sweden, March 23, 1976.

Duhl, R. W., "Methanol as a Boiler Fuel," Chemical Engineering Progress No. 75-76, July 1976.

Dunker, A. M., Atm. Environment Vol. 15, p. 1155, 1981.

Dutkiewicz, B., "Methanol Competitive with LNG In Long Haul" Oil and Gas J. No. 166-178, April 30, 1973.

Eberle, William R., "Coal Transportation by Rail in the Years 1985 and 2000," Proceedings of the 16th Intersociety Energy Conversion Engineering Conference, pp. 1166-1172, August 1981.

Ecklund, E. E., and Pefley, R. K., Characterization and Research Investigation of Alcohol Fuels in Automobile Engines, Final Report, DOE Contract No. DE-AC03-78CS, 1980.

Egan, T., The Potential for Converting California's Industrial Boilers to Coal, Consultant Report to California Energy Commission, November 1980.

Energy Information Administration, 1981 Annual Report to Congress (tele-con information on not-yet-released Regional Appendix).

Energy Modeling Forum, "Energy Modeling Forecast," World Oil, EMF Report 6, Stanford University, Stanford, Calif., Feb. 1982.

Eng, K. D., and Tierney, W. T., Facing the Future With an Engine and its Fuel Considered as a System, presentation to the Sixth Annual Meeting - District 6, The Canadian Institute of Mining and Metallurgy, Victoria, B.C., October 29-31, 1981.

Environmental Protection Agency, Grant of Application for a Fuel Waiver Submitted by the Atlantic Richfield Company (ARCO)--Decision of the Administrator.

EPRI, Coal-to-Methanol: An Engineering Evaluation of Texaco Gasification and ICI Methanol Synthesis Route, prepared by Fluor Corp., EPRI AP-1962, Project 832-4, Palo Alto, Calif., August, 1981.

EPRI, Economic Evaluation of the Coproduction of Methanol and Electricity with Texaco Gasification - Combined-Cycle Systems, EPRI AP-2212, Project 239-2, Palo Alto, Calif., January 1982.

EPRI, Production of Methanol from Lignite, prepared by Wentworth Brothers and C.F. Braun, EPRI AF-1161, TPS 77-729, Palo Alto, California, September 1979.

Eschenroeder, A. Q., and Martinez, J. R., American Chemical Society, Adv. Chem. Series Vol. 113, No. 101, 1972.

Evers, L. W., Fleming, R. D., and Hurn, R. W., "Efficiency and Emissions of a Stratified Charge Engine Optimization for Various Fuels," Society of Automotive Engineers, February 27 - March 3, 1978.

Faddick, R. R., "Flow Properties of Energy Slurries, Featuring Coal," Proceedings of the 3rd International Technical Conference on Slurry Transportation, No. 93-98, March 1978.

Falls, A. H., McRae, G. J., and Seinfeld, J. H., Int. J. Chemical Kinetics Vol. 11, No. 1137, 1979.

Falls, A. H., and Seinfeld, J. H., Environ. Sci. and Technol., Vol. 12, No. 1398, 1978.

Farmer, R. C., "Methanol-A New Fuel Source?" Gas Turbine International, May-June, 1975.

Ferm, J. C. and Muthig, P. J., A Study of the United States Coal Resources, JPL Publication, December 15, 1981.

Ferrall, J., Pappano, A., and Voecks, G., Methanol for Fuel Cells: Conditions for Availability, June 1980.

Fickett, A. P., "Fuel Cell Power Plants," Scientific American Vol. 239, p. 6, December 1978.

Finegold, J., Panel on Hydrogen Automotive Engine Performance, Fuel Economy and Emissions Potential at the World Hydrogen Energy Conference IV, June 16, 1982, IOM, SERI, June 23, 1982.

Finegold, J. G., Karpuk, M. E., McKinnon, J. T., and Pasamaneck, R., Demonstration of Dissociated Methanol as an Automotive Fuel: System Performance, presented at the AS/ISES 1981 Annual Conference, Philadelphia, Penn., May 27, 1981.

First Experiences with Alcohol-Gas Powered Methanol City Buses Used in Regular Service, Auckland, New Zealand.

Floris, T., and Scarpetti, M., "Methanol, Methanol, Methanol," sponsored by Chemical Week, Coal Week, and Coal Week International, New York, Dec. 1-2, 1981.

Foster-Pegg, R. W., Repowering of Large Steam Power Plants with Combustion Turbines Using Coal Derived Methanol and Other Fuels, Draft Report, California Energy Commission, Contract 300-79-042, May 1982.

Freeman, J. H., Alcohols - A Technical Assessment of Their Application as Fuels, API Publication No. 4261, July 1976.

Fydowski, R. A., and Cox, T. P., Methanol: Its Production, Use and Implementation. ASME.

Gangwal, S. K., Cleland, J. G., and Truesdale, R. S., Evaluation of Relative Environmental Hazards from a Coal Gasifier, EPA-600/57-81-100, Industrial Environmental Research Laboratory, U.S. Environmental Protection Agency, 1981.

Ghassemi, M., Iyer, R. Scofield, R., and McSorley, J., "Environmental Effects of Synfuel Use," Environ. Sci. and Technol., Vol. 15, No. 8, pp. 866-973, August 1981.

Ginevan, M.E., et al., Health and Environmental Effects for a High-Btu Coal Gasification Industry-1981, Argonne National Laboratory, U.S. Department of Energy, 1981.

Goldberg, J., Terasawa, K. L., and Voechs, G., U.S. Methanol Market: Long-Run Trends and Price Forecasts, JPL unpublished report, October 1979.

Graham, H., et al., "Methanol and Ethanol - Environmental, Health, and Safety Issues," Proceedings of the International Symposium on Alcohol Fuel Technology: Methanol and Ethanol, November 21-23, 1977, published by the U.S. Department of Energy, 1978.

Gross, R., "Emissions from Catalyst-Equipped California Cars - Customer Service," SAE Paper No. 800395.

Hagen, D. L., "Methanol as a Fuel: A Review with Bibliography," Alcohols As Motor Fuels, pp. 189-221, 1980.

Hagler, Bailley & Co., The Emerging U.S. Methanol Industry: Structure, Financing, and Marketing Strategies, exhibit 5.25, Feb. 1982.

Hahn, R. W., and Noll, R. G., "Designing a Market for Tradeable Emissions Permits," Social Science Working Paper No. 398, California Institute of Technology, Pasadena, California, July 1981.

Hallmark, F.O., Unconventional Petroleum Resource in California, Div. O&G, TR25.

Hanst, P. L., and Gay, B. W., Environ. Sci. and Technol. No. 11 p. 1105, 1977.

Harlen, James K., Starting with Synfuels: Benefits, Costs and Program Design Assessments, Ballinger Publishing Company, Cambridge, Mass., 1982.

Health, pp. 241-254, May 1974.

Heywood, John B., "Automotive Engines and Fuels: A Review of Future Options," Prog. Energy Combust. Sci., No. 7, pp. 155-184.

Hildebrand, R.T., "Coal Deposits in California, a Selected, Annotated Bibliography," California Geology, USGS, Denver, Colo., December 1978.

Hilden, D. L., and Parks, F. B., "A Single-Cylinder Study of Methanol Fuel - Emphasis on Organic Emissions," SAE Paper No. 760378, 1976.

Hirota, T., Study of the Methanol-Reformed Gas Engine.

Hull, R. M., An Overview of Octane Booster Markets, Alcohol as an Octane Enhancer in the 80's Conference, San Antonio, Texas, March 24, 1982.

ICF, Inc., Methanol from Coal: Prospects and Performance as a Fuel and as a Feedstock, prepared for the National Alcohol Fuels Commission, 1980.

Inagaki, T., Hirota, T., and Ueno, Z., Combustion and Emission of gaseous Fuel From Reformed Methanol in Automotive Engine.

Ingamells, J. C., and Lindquist, R. H., "Methanol as a Motor Fuel or a Gasoline Blending Component," SAE Paper No. 750123, 1980.

Ito, K., and Yano, J., Personal Communication, Dept. of Mech. Eng., Hokkaido Univ., Sapporo, Japan.

Juhasz, P. C., and Rossano, A. T., Proceedings from Fourth Joint Conference Sens. Environ. Pollution, pp. 101-104, American Chemical Society, 1977.

Kamaga, B. S., Krishnan, K. V., Murphy, B. S., Pefley, R. K., Bechtold, R. L., and Edwards, G. W., "Evaluation of Methanol for Reduced Exhaust Emissions in a Single-Cylinder Research Engine," Section II-24, Proceedings of the Third International Symposium on Alcohol Fuels Technology, Asilomar, California, 1979.

Keller, J. L., et al., Methanol Fuel Modification for Highway Vehicle Use - Final Report, DOE Contract No. EY-76-C-04-3683, July 1978.

Kermode, Dr. Richard I., et al., The Potential for Methanol from Coal: Kentucky's Perspective on Costs and Markets, Kentucky Department of Energy, December 1979.

Keystone Coal Industry Manual, 1981.

Kirk, R. E., and Othmer, D. F., Encyclopedia of Chemical Technology, The Interscience Encyclopedia, Inc., Vol. 6., New York, 1951.

Kirshenbaum, Noel W., A Preview of the Beluga Methanol Project, Placer Amex Inc., Alaska Coal Conference, University of Alaska, Fairbanks, Alaska, October 1980.

Komiyama, K., and Hashimoto, I., Spark-Assisted Diesel for Multifuel Capability, SAE Technical Paper Series, International Congress and Exposition, February 23-27, 1981.

Kuh, W. D., The Outlook for Methanol Blends for Use in Gasoline, March 24-25, 1982.

Kulp, G., et al., Transportation Energy Conservation Data Book: Edition 4," Oak Ridge National Laboratory for the U.S. Dept. of Energy, Report No. ORNL-5654, September 1980.

Kulp, G., Shonka, D. B., Holcombs, M. C., Transportation Energy Conservation Data Book: Edition 5, Oak Ridge National Laboratory, Report No. ORNL-5765, November 1981.

KVB Inc., Personal Communication, M. Mansour, May 1982.

Larsen, R. I., and Heck, W. W., "An Air Quality Data Analysis System for Interrelating Effects, Standards, and Needed Source Reductions: Part 3. Vegetation Injury," J. Air Pollution Control Assoc. No. 26, April 1976.

Lave, L. B., and Seskin, E. P., Air Pollution and Human Health, Johns Hopkins University Press, Baltimore, Maryland, 1977.

Lewis, J. M., and Tierney, W. T., Stratified Charge Engine Development with broad Fuel Tolerance, paper presented at First International Automotice Fuel Economy Research Conference, Alexandria, Va., October 31 - November 1, 1979.

Lewis, J. M., and Tierney, W. T., United Parcel Service Applies Texaco Stratified Charge Engine Technology to Power Parcel Delivery Vans, Progress Report, Truck Meeting, King-of-Prussia, Penn., Nov. 1978.

Liquid Fuels Trust Board, Preliminary Report, Project No. 6, Aukland, New Zealand, November 1, 1982.

Liquid Fuels Trust Board, Spirit of Transport, The Auckland Methanol Bus Experiment, Aukland, New Zealand.

Liquid Fuels Trust Board, Trial Programme on Methanol Diesel Buses, Project No. 3302/2, Auckland, New Zealand.

Litton Energy Systems, Barge-Mounted Methanol Conversion Plants, Houston, Texas, 1981.

Lloyd, A. C., et al., Environmental Research and Technology Report No. P-5287-500, Westlake Village, California, 1979.

Martin, G. B., and Heap, M. P., Evaluation of NO_x Emission Characteristics of Alcohol Fuels For Use In Stationary Combustion Systems, paper presented at the American Institute of Chemical Engineers Symposium: Impact of Methanol Fuel on Urban Air Pollution, Boston, Mass., September 1975.

Matsumoto, K., Matsumoto, T., and Goto, Y., "Reliability Analysis of Catalytic Converter as an Automotive Emission Control System," SAE Transactions, Vol. 84, No.750178.

Mayrsoh, H., Crabtree, J. H., Kuramoto, M., Sothern, R. D., and Mano, S. H., "Source Reconciliation of Atmospheric Hydrocarbons in 1974," Atmo. Environment, No. 11, p. 189, 1977.

McRae, G. J., Goodin, W. R., and Seinfield, J. H., Mathematical Modeling of Photochemical Air Pollution, Final Report to the California Air Resources Board, Environmental Quality Laboratory, Report No. 18, California Institute of Technology, Pasadena, California, 1982.

McRae, G. J., Goodin, W. R., and Seinfield, J. H., Atm. Environment, No. 16, p. 679, 1982.

McRae, G. J., and Seinfeld, J. H., "Development of a Second-Generation Mathematical Model for Urban Air Pollution - II Evaluation of Model Performance," Atm. Environ., 1982.

Mendelsohn, R., "An Economic Analysis of Air Pollution from Coal-Fired Power Plants," J. Environ. Econ. and Management, No. 7, pp. 30-43, 1980.

Menrad, H., A Motor Vehicle Powerplant for Ethanol and Methanol Operation, Paper II-26 presented at the Third International Symposium on Alcohol Fuels Technology, May 29-31, 1979.

Mercedes-Benz, Directory of Diesel Fuel Stations and Authorized Mercedes-Benz Dealers, Montvale, New Jersey, 1978 through 1982.

Millecan, A. A., A Survey and Assessment of Air Pollution Damage to California Vegetation in 1979, California Department of Agriculture, 1971.

Miller, D. R., "Methanol From Coal", Proceedings of the Conference on Coal use for California, JPL Publication 78-56, August 1978.

Mining Information Services, 1981 Keystone Coal Industry Manual, 1981.

Moriarty, A. J., "Toxicological Aspects of Alcohol Fuel Utilization," Proceedings of the International Symposium on Alcohol Fuel Technology: Methanol and Ethanol, November 21-23, 1977, published by the U.S. Department of Energy, 1978.

Morrow, Edward W., et al., A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants, DOE, R-2481-DOE, Rand Corporation, July 1979.

Muzio, L. J., and Arand, J. K., "Utility Boiler Repowering with Methanol: Effect on NO_x Emissions, prepared by KVB, Inc., for Conoco Coal Development Co., 1981.

MVMA Motor Vehicle Facts and Figures, 1979, prepared by Motor Vehicle Manufacturers Association, Detroit, Michigan.

Myronuk, D. J., "Augmented Ingestion of CO and SO sub x & by Occupants of Vehicles while Idling in Drive-up Facilities," Water, Air, Soil Pollution, No. 7, p. 203, 1977.

National Institute for Occupational Safety and Health, U.S. Department of Health and Human Services, "Formaldehyde: Evidence of Carcinogenicity," Current Intelligence Bulletin 34, April 15, 1981

Neitz, A., and Chmela, F., Results of Man-FM Diesel Engines Operating on Straight Alcohol Fuels.

Norris-Jones, S. E. and Russell, J. T., "'FM' - A High Efficiency Combustion System for the Future Light-Duty Engine,?" The Engineering Resource for Advance Mobility, June 7-10, 1982.

Noyes Data Corp., Methanol Technology and Application in Motor Fuels, Park Ridge, New Jersey, 1978.

Oak Ridge National Laboratory, Transportation Energy Group, Motor Vehicle MPG and Market Shares, March 1982.

Office of Technology Assessment, An Assessment of Oil Shale Technologies, OTA-M-118, June 1980.

Office of Technology Assessment, Energy From Biological Processes: Technical and Environmental Analyses, Volume I, OTA-E-124, July 1980.

Office of Technology Assessment, Energy From Biological Processes: Technical and Environmental Analyses, Volume II, OTA-E-128, September 1980.

Office of Technology Assessment, Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Impacts, OTA-E-185, September, 1982.

Oklahoma, University of, and Radian Corporation, Energy from the West, progress report of technology assessment of western energy resource development, Volume IV Appendices, July 1977.

OTA, Increased Automobile Fuel Efficiency and Synthetic Fuels, September 1982.

Patterson, P., Additional Sensitivity Runs of the BNL Fleet Operator's Applicability Model, DOE letter to interested parties, May 4, 1978.

Patterson, P., Initial Finding of BNL's Fleet Operators Study, DOE letter to interested parties, April 27, 1978.

Paul, J. K., editor, Methanol Technology and Application in Motor Fuels, published by Noyes Data Corporation, pp. 82-100, 1978.

Pefley, R. K., et al., Alcohol Fueled Vehicles Performance and Emissions, University of Santa Clara, paper prepared for Carnegie-Mellon Institute of Research, August 1981.

Pefley, R. K., Characterization and Research Investigation of Alcohol Fuels in Automobile Engines, University of Santa Clara, Report No. ME-80-1, December 1980.

Perera, F., and Petito, C., "Formaldehyde: A Question of Cancer Policy?," Science, p. 216, June 1982.

Petrie, T. W., Rhodes, W. J., and Page, G. C., Environmental Aspects of Coal Gasification and Liquefaction Processes, paper presented at A.I.Ch.E. Symposium on Environmental Assessment of Solid Fossil Fuel Processes: Part I, November 12-16, 1978.

Petroleum Supply Alternatives for the Northern Tier and Inland States, Through Year 200, DOE-RA-0042-2, Vol. II, October 31, 1979.

"Petro Mine" Engineering and Mining J., June 1981.

Pikulik, A., and Diaz, H. E., "Cost Estimating For Major Process Equipment," Chemical Engineering, pp. 106-122, October 10, 1977.

Pischinger, F. F., and Kramer, K., "The Influence of Engine Parameters on the Aldehyde Emissions of a Methanol-Operated Four-Stroke Otto Cycle Engine," Section II-25, Proceedings of the Third International Symposium on Alcohol Fuels Technology, Asilomar, California, 1979.

Predicasts Inc.'s, Basebook, Bureau of Labor Statistics, U.S. Dept. of Commerce, Chemical Engineering News, 01/22/79, 01/28/80, 01/26/81, 03/29/82.

Purohit, G., and Houseman, J., "Methanol Decomposition Bottoming Cycle for IC Engines", SAE Paper No. 790427.

Radian Corporation, Assessment of Advanced Coal-Based Technologies for Use in California, California Energy Commission Report P300-80-036, 1980.

Raible, C. J., and Cox, F. W., "Chromatographic Methods of Analysis for Methanol and Ethanol in Automotive Exhuast," SAE Paper No. 790690, 1979.

Ravishankara, A. R., and Davis, D. D., J. Phys. Chem., No. 82, p. 2852, 1978.

Revty, R. C., and Timbari, T. J., Status of Alcohol Fuels Utilization Technology for Stationary Gas Turbines, report prepared by Mueller Assoc., Inc. for DOE HCP/M2098-01, April, 1979.

Reynolds, S. D., Roth, P. M., and Seinfield, J. H., Atm. Environ. No. 7, p. 1033, 1973.

Riley, R., Coal Transportation Capability of the Existing Rail and Barge Network, 1985 and Beyond, prepared by Manalytics, Inc. for EPRI, EPRI EA-237, Sept. 1976.

Rogers, K. A., Hill, R. F., Coal Conversion Comparisons, Engineering Societies Commission on Energy Inc., FE-2468-51, DOE Contract EF77-C-01-2468, Washington, D. C., July 1979.

Rogers, K. A., Hill, R. F., et al., Synthetic Fuels Summary, Engineering Societies Commission on Energy Inc., FE-2468-82, DOE Contract DE AC01-77-ET-10679, Washington, D. C., March 1981.

Rolnick, Paul D., et al., Alternate Strategies for Stationary and Mobile Engines: Evaluation of Clean Coal Fuels, Vol. III, PACE Corporation under contract to Accurex Corp., FR-81-99/EE Mountain View, California, July 1981.

Rischard, J. F., Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries, World Bank, Washington, D. C., ISBN 0-8213-0018-0, April 1982.

Rudolph, F. H., and Herbert, P. K., Conversion of Coal to High Value Products, Lurgi, Symposium on Coal Gasification, Liquefaction and Utilization, University of Pittsburgh, Penn., August 1975.

Rudolph, F. H., The Art of Coal Gasification. Fourth International Sumposium on Chemical Reaction Engineering, University of Heidelberg, April 1976.

Rubin, B., et al., An Assessment of the Potential for Use of Alaskan Coal in California, Lawrence Livermore Laboratory, Report No. UCRL-52511, June 1978.

Ruderman, H., et al., Regional Environment - Energy Data Book, Western Region, Lawrence Berkeley Laboratory for the U.S. Dept. of Energy, Report No. DOE/TIC-10114/2, December 1978.

Sammons, D., The Synfuels Plant Siting Guide: A State-by-State Analysis, McGraw-Hill Publications Co., New York, 1981.

Santhanam, C. J., et al., "Non-Water Slurry Pipelines - Potential Techniques," Proceedings of the Fifth International Technical Conference on Slurry Transportation, pp. 93-103, March 1980.

Seigneur, C., Tesche, T. W., Roth, P. M., and Reid, L. E., J. Applied Meteorology, No. 20, p. 50, 1981.

Seinfeld, J. H., Air Pollution: Physical and Chemical Fundamentals, McGraw-Hill, Inc., New York, 1975.

Seinfeld, J. H., Lectures in Atmospheric Chemistry, AIChE Monograph Series, No. 12, p. 76, 1980.

Sema, T., Hoshizawa, K., Sonoda, K., Endo, K., and Mizuochi, H., Study on Methanol Combustion, paper presented at the Fourth International Clean Air Congress.

Shonka, D. B., editor, Transportation Energy Conservation Data Book, Edition 3, Oak Ridge National Laboratory for the U.S. Dept. of Energy, Report No. ORNL-5493, February 1979.

Sixty-fifth Annual Report of State Oil and Gas Supervisor, PRO6, California Division of Oil and Gas, 1979.

Slonski, M. L., Energy Systems Economic Analysis (ESEA) Methodology and User's Guide, JPL 5101-102, February 15, 1979.

Socdjanto, P., and Schaffert, F., "Transporting Gas - LNG vs. Methanol," Oil and Gas J., pp. 88-92, June 11, 1973.

South Coast Air Quality Management District and Southern California Association of Governments, Draft Air Quality Management Plan, 1982 Revision: Appendix No. VII-A, Short Range Tactics for the South Coast Air Basin, August 1982.

South Coast Air Quality Management District and Southern California Association of Governments, Draft Air Quality Management Plan, 1982 Revision: Appendix No. VIII-A, Energy Use and Alternative Vehicle Fuels, August 1982.

South Coast Air Quality Management District and Southern California Association of Governments, Draft Air Quality Management Plan, 1982 Revision: Appendix No. VIII-D, Energy Use and Alternative Vehicle Fuels, August 1982.

South Coast Air Quality Management District, Air Quality Management Plan, 1979.

South Coast Air Quality Management District, Air Quality Management Plan, 1982 Revision, June 1982.

South Coast Air Quality Management District and Southern California Association of Governments, Draft Air Quality Management Plan: 1982 Revision, August 1982.

South Coast Air Quality Management District, Regulation XIII, as amended September 10, 1982.

Southern California Association of Governments, Personal Communication from Millie Yamata, June 1982.

Southern California Association of Governments, SCAG-78 Growth Forecast Policy, October 1978.

Southern California Edison Company, Common Forecasting Methodology IV Supply Plan, April 1982.

Southern California Edison Company, Supply Plans for Common Forecasting Methodology III, June 1980.

Spofford, W. O., Jr., Parker, A. L., and Kneese, A. V., eds., "Energy Development in the Southwest," Research Paper R-18, Resources for the Future, Washington, D.C., 1980.

SRI, Chemical Engineering Handbook.

SRI International, Environmentally Based Siting Assessment for Synthetic Liquid Fuels Facilities, prepared for the U.S. Department of Energy, DOE/EV-10287, 1980.

SRI International, Synthetic Liquid Fuels Development: Assessment of Critical Factors, Vol. II, prepared for the U.S. Energy Research and Development Administration, ERDA 76-129/1, 1976.

Stephens, R., Freeman, J., and Evans, M. J., "Early Response of Lung to Low Level of Nitrogen Dioxide," Arch. Environ. Health, No. 3, pp. 311-20, 1972.

System Development Corporation, Strategic Study of Synfuel Commercialization, TM-6158-014-00, Union Carbide Corp., Oak Ridge, Tennessee, January 1981.

Taylor, W. D., et al., Int. J. Chem. Kin. No. 12, p. 231, 1980.

Teel, H. L., Multi-Products Pipelining of Ethanol/Hydrocarbon Blends" and Transportation of Fuel Grade Ethanol by a Multi-Products Pipeline, papers presented at Alcohol as an Octane Enhancer in the 80's conference, San Antonio, Texas, March 24-25, 1982.

TEKNEKRON, Municipal Solid Wastes and Agricultural Residues vs. Coal as an Energy Feedstock, Berkeley, California, March 1977.

TERA, Inc. Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates, prepared for the U.S. Dept. of Energy, Report No. DOE/EIA-0102/47, January 1979.

Terasawa, K. L., and Whipple, D. W., Regional Price Targets Appropriate for Advanced Coal Extraction, JPL Publication 80-91, December 1, 1980.

"The Engines of the Future, Transition 1: The Multi-Fuel Engine," Fleet Owner, January 1980.

"The World of the 'World Truck'," Fleet Owner, July 1980.

Tilden, J. W., and Seinfield, J. H., Atm. Environ., No. 6, p. 1357, 1982.

Trijonis, J., and Yuan, K., Visibility in the Northeast: Long-Term Visibility Trends and Visibility-Pollutant Relationships, U.S. Environmental Protection Agency, Document EPA-600/3-78-075, 1978.

Trijonis, J., and Yuan, K., Visibility in the Southwest: An Exploration of the Historical Data Base, U.S. Environmental Protection Agency, Document EPA-600/3-78-039, 1978.

UPS Engine Ready for Real-Life Test," Diesel Equipment Superintendent, February 1982.

U.S. Department of Energy, Assessment of Methane-Related Fuels for Automotive Fleet Vehicles, February 1982.

U.S. Department of Energy, Characterization of Seven United States Coal Regions, DOE/ET/10023-2, February 1981.

U.S. Department of Energy, Cost Guide - Cost Factors: Capital and Operations and Maintenance Factors of Representative Energy Systems and Facilities, Volume 3, DOE/MA-0063, April 1982.

U.S. Department of Energy, Environmental Analysis of Synthetic Liquid Fuels, DOE/EV-0044, 1979.

U.S. Department of Energy, Environmental Readiness Document: Coal Gasification, Commercialization Phase III Planning, DOE/ERD-0012, 1978.

U.S. Department of Energy, Synthetic Fuels and the Environment: An Environmental and Regulatory Impacts Analysis, Review Draft, 1980.

U.S. Environmental Protection Agency, Methods of Development for Assessing Air Pollution Control Benefits, EPA-600/5-79-001.

Wagner, J. R., and Davis, R. S., Fleet Operator Study, Interim Briefing, presented at DOE/TEC CCM at ANL on September 14, 1978.

Wagner, J. R., Naughton, J., and Brooks, W.P., Light Duty Highway Fleets, Interim Briefing for Department of Energy, March 3, 1948.

Wagner, Joseph R., Fleet Operator Data Book, Vol. 1, National Data, Brookhaven National Laboratory, BNL 50904, September 1979.

Wagner, Joseph R., Fleet Operator Data Book, Vol. 2, Regional Data, Brookhaven National Laboratory, Draft, July 1949.

Wagner, J., and Naughton, J., Fleet Operator Study: Geographic Aspects, Brookhaven National Laboratory, BNL, Informal Report 24708, July 1978.

Weir, A., et. al., Investigation of Methanol as a Boiler Fuel for Electric Power Generation, draft report, EPRI Research Project RP 1412-11, June 1982.

Weir, A., von KleinSmid, W. H., and Sanko, E. A., Test and Evaluation of Methanol in a Gas Turbine System, Final Report prepared by Southern California Edison Co. for EPRI, Research Project 988-1.

Weismantel, Guy E., "Methanol Supplies: Too Much or Too Little?" Chemical Engineering, July 14, 1980.

White, L. J., The Regulation of Air Pollutant Emissions From Mobile Sources, Draft Publication, Graduate School of Business Administration, New York University, 1981.

White, W. H., and Roberts, P. T., "On the Nature and Origins of Visibility-Reducing Aerosols in the Los Angeles Air Basin," Atm. Environ., No. 12, pp. 779-784, 1977.

Wigg, E. E., and Lunt, R. S., "Methanol as a Gasoline Extender - Fuel Economy, Emission and High Temperature Driveability," SAE Paper No. 741008, Alcohols as Motor Fuels, 1980.

Wimer, R. L., Adams, M. A., and Jurich, D. M., Characterization of Seven United States Coal Regions, Kaiser Engineers, Inc., and TRW, Inc., for the U.S. Department of Energy, February 1981.

Winter, C., and Kohll, A., "Energy Imports: LNG vs. MeOH," Chemical Engineering, No. 80, pp. 233-238, November 12, 1973.

APPENDIX A

GLOSSARY

UNITS OF CONVERSION

APPENDIX A

GLOSSARY

ϕ	air/fuel equivalence ratio
η	thermal efficiency
^{o}C	degrees Centigrade
^{o}F	degrees Farenheit
$	dollars
¢	cents
A/F, AF	air/fuel ratio
AC	alternating current
ANL	Argonne National Laboratories
AO	annual output
APCD	Air Pollution Control District
API	American Petroleum Institute
ARB, CARB	California Air Resources Board
ARCO	Atlantic-Richfield Company
ASTM	American Society of Testing Materials
BACT	Best Available Control Technology
BBEC	breakeven busbar energy cost
BBEC	levelized price
BBL, bbl	barrel
Bcf	billion cubic feet
B/D	barrels per day
BIT	bituminous
BMMP	barge-mounted methanol plant
Btu	British thermal unit
C	carbon
CAA	United States Clean Air Act
CAFE	corporate average fuel economy
Cc	capital cost
C_cC_c'	levelized capital cost
C_j	annual operation and maintenance costs
CEC	California Energy Commission
CENT	central
CEQ	Council on Environmental Quality
CEQA	California Environmental Quality Act
CF	cubic feet
CFR	cooperative fuel research
CI_{PV}	present value of recurring costs
CI_{nom}	nominal annual sum of investment expenditures
CO	carbon monoxide
CO_2	carbon dioxide
CR	compression ratio

CRC	Coordinating Research Council
CRF	capital recovery factor
CRIEPI	Central Research Institute of the Electric Power Industry (Japan)
CST	centistokes
Cv	variable cost
CWA	Clean Water Act
DC	direct current
DOT	Department of Transportation
DPF	depreciation factor
DRI	Data Resources Incorporated
DWT	dead weight tons
EFI	electric fuel ignition
E,H&S	environmental, health and safety
EHV	extra high voltage
E_j	escalation rate for recurrent costs
Emsn	emissions
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERC	Energy Research Corporation
ESEA	Energy Systems Economic Analysis
Evap	evaporation
FCCU	fluidic catylaic cracking unit
FG	flue gas
FOC	fixed operating cost
FT^3, ft^3	cubic feet
FT, ft	feet
FWT	front wheel traction
g	grams
gal	gallon
GE	General Electric
G/M	grams per mile
GM	General Motors
GNP	gross national product
GPM	gallons per minute
GTBA	gasoline-grade teriary butyl alcohol
H	hydrogen
H_2O	water
H_2S	hydrogen sulfide
H/C	hydrogen/carbon molecular ratio
HC	hydrocarbons
HHV	higher heating value
Hr, hr	hour
HVDC	high voltage direct current
I	pretax amount to amortize original capital investment

ICI	Imperial Chemical Industries
ID, id	inner diameter
ITC	investment tax credit
IW	inertial weight
JPL	Jet Propulsion Laboratory
k	general discount rate
kg	kilogram
KJ	kilojoule
km/L	kilometers per liter
KPa	kilopascal
K-T	koppers-Totzck
KV	kilovolt
kW-hr	kilowatt-hour
KW, kW	kilowatt
L.A.	Los Angeles
LADWP	Los Angeles Department of Water and Power
LAER	Lowest Achievable Emission Rates
LB, lb	pound
LCC	life-cycle costs
LHV	lower heating value
LNG	liquefied natural gas
LoLP	loss of load probability
M	meters
M^3	cubic meters
MBT	maximum brake torque
MBT	minimum spark advance for best torque
Mcf	thousand cubic feet
MeOH	methanol
MF	moisture free
mi	mile
MISC	miscellaneous expense rate
Mkt	market
mm	millimeter
MMBtu	million British thermal units
Mol	molecular
MPG, mpg	miles per gallon
MSHA	Mining Safety and Health Administration
MSW	municipal solid wastes
MTBE	methyl tertiary butyl ether
MTD	metric tons per day
MW, MWe	megawatt
N	nitrogen
NEPA	National Environmental Policy Act
NG	natural gas
NO_x	nitrogen oxides
No.	number
NPDES	National Pollutant Discharge Elimination System

NSPS	New Source Performance Standards
O_2	oxygen
OH	hydroxyl radical
O&M	operation and maintenance
ON	octane number
ONB	octane number barrel
ONBC	octane number barrel cost
OSHA	Occupational Safety and Health Administration
OSM	U.S. Office of Surface Mining, Department of the Interior
PAD	petroleum allocation district
PAFC	phosphoric acid fuel cell
PAN	peroxyacetyl nitrate
PCB	polychlorinated biphenyl
Pet	petroleum
POTWs	public owned treatment works
ppm	parts per million
ppmv	parts per million by volume
ppmw	parts per million by weight
P_RP_R'	levelized total cost
PSD	Prevention of Significant Deterioration
PSI, psi	pounds per square inch
PSIA	pounds per square inch, absolute
PSIG	pounds per square inch, gauge
PUC	Public Utilities Commission
QUAD, Quad	quadrillion ($1x10^{15}$)
r	investor's discount rate
RCRA	Resource Conservation and Recovery Act
RDH	removable dome head
RESID	residual
RG&E	Pacific Gas and Electric
RNG	remote natural gas
RR	railroad
RVP	Reid vapor pressure
S	sulfur
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SCF	standard cubic feet
SCFD	standard cubic feet per day
Sec	second
SHED	sealed housing for evaporative emissions
SIP	State Implementation Plan
SMCRA	Surface Mining Control and Reclamation Act
SNG	synthetic natural gas or syngas
So	south
SO_2	sulfur dioxide

SO_3	sulfur trioxide
ST	standard ton
STD	standard tons per day
syn crude	synthetic crude oil
T/D,TD, TPD, tpd	tons per day
TBA	tertiary butyl alcohol
TBtu	trillion british thermal units
Tcf	trillion cubic feet
TCGP	Texaco Coal Gasification Process
TCR	total capital requirement
TPI	total plant investment
TR	tax rate
TSCA	Toxic Substances Control Act
TT	tangent to tangent
UBF	unburned fuel
UC	uniform change
UTC	United Technology Corporation
V-8	eight cylinder internal conbustion engine with "V" configural block
VOC	variable operating cost
VOL, vol	volume
W	watts
WOT	wide open throttle
WT, wt	weight
WY	Wyoming
YR, yr	year

APPENDIX A

UNITS OF CONVERSION

To Convert From	To	Multiply By
atmospheres	pounds/sq. in.	14.70
barrels (oil)	gallons (oil)	42.0
Btu	foot - lbs	778.3
Btu	kilowatt-hrs	2.928×10^{-4}
Btu/hr	watts	0.2931
Centigrade	Fahrenheit	$(C^{o} \times 9/5) + 32$
cubic feet	gallons (U.S. liquid)	7.48052
gallons	liters	3.785
gallons/minute	cubic feet/second	2.228×10^{-3}
grams	joules/meter (newtons)	9.807×10^{-3}
grams	pounds	2.205×10^{-3}
grams/liter	pounds/cubic feet	0.062247
horsepower	foot-pounds/second	550.0
horsepower	kilowatts	0.7457
horsepower-hours	Btu	2,547.0
joules	Btu	9.480×10^{-4}
joules/centimeter	grams	1.020×10^{4}
kilograms	pounds	2.205
kilowatt-hours	Btu	3,413.
kilowatts	Btu/minutes	56.92
knots	nautical miles/hour	1.0
knots	statute miles/hour	1.151
liters	gallons (U.S. liquid)	0.2642
meters	feet	3.281
miles (statute)	meters	1,609
pounds/square inch	kilograms/square meter	703.1
tons (long)	pounds	2,240.
tons (metric)	pounds	2,205.
tons (short)	pounds	2,000.
watts	Btu/hour	3.4129
watts	horsepower	1.341×10^{-3}

APPENDIX B

EXHIBIT OF SPONSOR REVIEW COMMENTS

The sponsoring organizations of the California Methanol Assessment were invited to submit comments on the final report for inclusion in the Report. Comments received in time for printing are presented in this appendix. At the time of printing, the following sponsors had not submitted comments:

California State Energy Resources Conservation and Development Commission

Chevron, USA

E. I. du Pont de Nemours and Company, Inc.

Exxon Research and Engineering Company

Ford Motor Company

Phillips Petroleum Company

Texaco, Inc.

ARCO Petroleum Products Company
515 South Flower Street
Mailing Address: Box 2679 - T.A.
Los Angeles, California 90051
Telephone 213 486 0941

J. O. Siemssen
Manager
Technical Coordination
Research and Engineering

March 18, 1983

Mr. Richard P. O'Toole
Methanol Task Manager
Jet Propulsion Laboratory
4800 Oak Grove Drive
Pasadena, California 91109

Dear Richard:

We have reviewed the California Methanol Assessment, and wish to compliment you and the staff at both JPL and CalTech who participated in the study on a comprehensive job, well done. In general we believe the study is a reasonable assessment of methanol in California, particularly in the near term.

For the longer term, the projection of the potential for methanol may be somewhat conservative. Given the fact that large scale production and utilization of methanol as a fuel has only recently gained detailed attention, it seems probable that there will be future advances in both these areas which will impact the time frame for the growth of methanol in the marketplace. This is an area which could use further work.

A second area deserving additional attention is the assessment of the environmental consequences which widespread methanol use will have. While the initial results appear interesting, a more detailed technical review is warranted, particularly in view of results obtained in other studies.

We have appreciated the opportunity to have been a part of this study. The effort which you and the study team have put into consolidating the diverse input from the sponsors group has made this assessment particularly worthwhile.

Sincerely,

John O. Siemssen
Manager, Technical Coordination
Research and Engineering
ARCO Petroleum Products Company
Atlantic Richfield Company
Los Angeles, California

JOS/vlk

Conoco Inc.
High Ridge Park
Stamford, CT 06904
(203) 329-2300

March 17, 1983

Mr. Richard P. O'Toole
Jet Propulsion Laboratory
California Institute of Technology
4800 Oak Grove Drive
Pasadena, California 91109

Dear Rich:

While we have some reservations about small details of the analysis presented in the report we, as a sponsor of the project, are satisfied that the report largely addresses the questions in our minds when we first accepted sponsorship of the program.

The initial concept of this evaluation depended on Caltech/JPL obtaining advice and information from the sponsors sufficient for them to make a reasonable independent assessment of the value of methanol as a fuel in California. The investigators have made a creditable effort to present data obtained from us, and other sponsors, in an informative way and have been able to draw pertinent conclusions from it.

Within the limits set by time and cost, we feel we will be receiving a document adequate for our purpose.

One subject we would have liked to see developed, and which we believed was to be covered according to the original outline, was analysis of institutional factors peculiar to California which could influence the introduction of methanol as a fuel independent of economics should a supply be available. We were aware before the study began that various bills had been presented to the Sacramento legislature attempting to mandate the use of methanol as a fuel and that some bills had passed making it legal to use methanol. While we did not expect any conclusions on the likelihood of any legislation being successful, it would have been helpful to non-residents of California to have available an assessment of the influence on the marketplace of socio/political forces, and how these might induce the use of methanol,if it became available in large quantities, even if it was clearly non-competitive economically (e.g. mandated to reduce emissions).

(Continued)

Mr. Richard P. O'Toole
California Institute of Technology

March 17, 1983

In terms of economics, the crude oil price forecast taken from DRI's Spring 1982 Energy Review is clearly now out of date. Since the spring of last year DRI, as have Conoco and most other energy industry analysts, have lowered their projections of the likely path of oil prices. At the time many of the comparisons in the study were made, the lowest price sensitivity, which is that most close to present day forecasts, was assigned a probability of only 5 percent. Today that projection is almost identical to Conoco's forecast. Clearly it is impossible to re-write the report to take these changes into account, but I believe it would be appropriate for you to point it out in a covering letter or addendum to the executive summary. In making such a statement care should be taken to show that these changes do not affect some of the conclusions (the use in light vehicles for instance) so much as the timing.

It was a pleasure to work with you and your colleagues on this project and I look forward to receiving the final report.

Sincerely,

Robert G. Jackson

YV

March 15, 1983

EPRI

Dr. Richard P. O'Toole
Jet Propulsion Laboratory
California Institute of Technology
4800 Oak Park Drive
Pasadena, CA 91109

Dear Dr. O'Toole:

We have reviewed the draft volumes summarizing the California Methanol Assessment that has been prepared. During the project there has been opportunity for the sponsors of the project to meet with the project team to provide information that has been summarized.

The conclusions with regard to methanol use for stationary combustion application are reasonable. It is not presently attractive to utilize methanol instead of directly using natural gas or petroleum production in California for electricity generation. The use of methanol in large quantities is not likely to occur for several decades. Thus, the production and utilization of methanol requires further development to improve its relative economic incentive.

Costs are presented in the report for methanol derived from a variety of feed stocks using different processing routes. These costs were from work that were not originally generated by the project, in that there was already a large body of information on the topic. With the available funding, it was not considered prudent to duplicate such cost information, thus, the cost data which appear in the study should not be considered definitive information.

A recommendation to the California Energy Commission (p. 19) is that they should consider support of development of coal gasification combined cycle plants that incorporate "once through" methanol processing schemes that would co-produce electricity and methanol. The report does not contain specific information on the status of these technologies.

Enclosed is an attachment from the EPRI Journal on the status of the "once through" methanol processing scheme and a description of the program that is being performed and partially supported by the Electric Power Research Institute in collaboration with industrial organizations.

The R&D work is well launched in that a 100 MW coal gasification combined cycle plant is under construction at the Cool Water site of the Southern California Edison Co. The plant is to start up in June 1984 and operate for several years at that site. In addition, the "once through" methanol route is also at a pilot plant scale in Texas where a 3 ton/day unit is under construction. Thus, the technology for "once through" methanol will not be technically ready until the late 1980's based on current programs.

Headquarters: 3412 Hillview Avenue, Post Office Box 10412, Palo Alto, CA 94303 (415) 855-2000

Washington Office: 1500 Massachusetts Avenue, NW, Suite 700, Washington, DC 20036 (202) 872-9222

The report is an excellent source document, and the conclusions are reasonable and derive from the information that has been summarized.

Taking into account the diverse interests of the sponsors, the Jet Propulsion Laboratory and the California Institute of Technology performed a difficult job of assessing this complicated area.

Very truly yours,

S. B. Alpert

S. B. Alpert
Technical Director
Advanced Power Systems Division

SBA/mb

Attachment

cc: H. H. Gilman
E. F. Kapielian - PGE
Charles B. McCarthy - SCE
D. Spencer

General Motors Research Laboratories
Warren, Michigan 48090-9055

March 18, 1983

Dr. Richard P. O'Toole
Jet Propulsion Laboratory
California Institute of Technology
4800 Oak Grove Drive
Pasadena, California 91109

Dear Dick:

You, and the Staffs from JPL and Cal Tech, are to be congratulated for the comprehensive report on "California Methanol Assessment." You have distilled a tremendous amount of material, and a variety of opinions where hard factual information was not available, into a report that both makes sense and has credibility.

The title of the report may imply that it pertains to only the State of California. However, this is far from the truth. The report's contents are widely applicable to the United States as a whole, and even to other countries interested in methanol. Thus, I expect the report to attract widespread interest.

The major conclusion of the report, that the time for widespread utilization of methanol is at least ten to fifteen years away, is based, as it should be, primarily on economic considerations. Thus, California, and our nation should not have to mount a panic effort to ensure that large quantities of methanol are available and that users are ready for it in the next several years. The current situation with respect to petroleum and natural gas availability and price should provide California and the nation with the time to take an orderly approach to the time, which will ultimately come, when alternatives to petroleum will be necessary. Your report points out that methanol, initially from natural gas, and ultimately from coal, is a leading candidate as an alternative fuel for automobiles. Our studies at General Motors have also come to the same conclusion.

The report contains considerable discussion of the potential environmental benefits of substituting methanol for gasoline as an automotive fuel. However, I believe that the text of the report, in several places, overstates the atmospheric benefits achievable in the Los Angeles basin by such a substitution. Data in the report (Figure 6-2 in Volume I: Summary Report) indicate that there may be only marginal benefits in peak ozone concentration reduction in the year 2000. For example, complete substitution of methanol for gasoline, reduces peak ozone by only 14.4 percent. It is highly unlikely that there will ever be such a complete

substitution. The report also implies that automobiles fueled with methanol will have lower NO_X emissions than comparable gasoline-fueled automobiles (because of the inherently lower NO_X production in the combustion process with methanol's lower peak combustion temperature). In practice, however, this will not occur because the NO_X exhaust emission standard is the same for either fuel, and the inherently lower NO_X with methanol can be traded off for improved fuel economy and/or performance. Also, data in the report (Figure 6-2 again) show that there is essentially no atmospheric benefit to having methanol fueled vehicles with 50 percent of the NO_X emissions of their gasoline counterparts. Peak ozone is reduced from 0.285 to 0.275 ppm, only a 3.5 percent reduction.

The report also contains a significant comment with respect to the role of emissions from gasoline-fueled vehicles in contributing to photochemical smog in Los Angeles in the year 2000. In one of the atmospheric modeling cases, these emissions were set equal to zero. This resulted in a reduction of peak ozone of 25 percent, indicating that nonautomotive emissions are the primary contributor to photochemical smog in Los Angeles by the year 2000.

The main conclusion in the report regarding the air-quality impacts of methanol is that, "the use of methanol in motor vehicles could form part of an effective long-term strategy to reduce air pollution in the South Coast Air Basin." I believe the data in the report, as mentioned above, do not support this conclusion. Use of methanol in motor vehicles could have marginal benefits. However, more significant benefits would be achieved by controlling nonautomotive sources in the same vigorous manner in which automotive emissions have been controlled.

Dick, I appreciated the opportunity to represent General Motors on your Technical Advisory Group, and I know that I and General Motors have benefitted from this association. Good luck to you and the Staffs from JPL and Cal Tech on your next assignments.

Sincerely,

Joseph M. Colucci, Head
Fuels and Lubricants Dept.

JMC/ljl

PACIFIC GAS AND ELECTRIC COMPANY

PG&E 245 MARKET STREET • SAN FRANCISCO, CALIFORNIA 94106 • (415) 781-4211

E. F. KAPRIELIAN
VICE PRESIDENT—FUELS PLANNING AND ACQUISITION

March 11, 1983

Dr. Richard P. O'Toole
Jet Propulsion Laboratory
California Institute of Technology
4800 Oak Grove Drive
Pasadena, California 91109

Dear Dr. O'Toole:

The California Methanol Assessment Report is a comprehensive analysis of the prospective use of methanol as a fuel in California. The results and conclusions in the report will provide an excellent basis for our fuels planning and future action. We expect this report to receive wide circulation and to serve as a reference document on methanol for many years to come.

We fully support the conclusion that methanol's contribution to the future California energy mix will be very limited. Methanol is not cost competitive with oil, natural gas and other fuel alternatives as a power plant boiler fuel. However, methanol may prove viable for specific electric utility applications, given more testing and perhaps special incentives.

Although this was a very difficult study, considering the diverse sponsor interests, we commend Jet Propulsion Laboratory and the California Institute of Technology for their efforts in carrying out a comprehensive independent assessment. PGandE is pleased to have been involved in this important study, and we congratulate you and the study team for an excellent job.

Sincerely,

E. F. Kaprielian

Solar Energy Research Institute
1617 Cole Boulevard
Golden, Colorado 80401
(303) 231-1000

235-JGF-3084

March 22, 1983

Richard P. O'Toole, Leader
California Methanol Assessment
Jet Propulsion Laboratory
4800 Oak Grove Drive
Pasadena, CA 91109

Dear Rich:

I think that you and your team have done a good job on a study that included the very difficult tasks of synthesizing trends and conclusions from limited and sometimes conflicting data and predicting the future. Since the validity of your conclusions and the advisability of your recommendations depend on your view of the future, it is unlikely that anyone will totally agree with you (or anyone else) on the future of methanol in California.

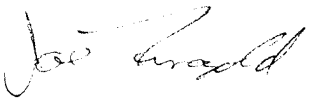
Of particular interest to me is the work you have done on methanol utilization. I believe that there is greater uncertainty on the efficiency potential of liquid methanol, vaporized methanol and, in particular, dissociated methanol than does the JPL team. There has not been very much research done on optimization of engines (e.g., combustion chamber geometry, port design, ignition system, etc.) for these fuels, so their potential is less well understood than the venerable gasoline engine.

The nature of the fuel economy comparisons also has a fundamental effect on the results. An equal performance methanol vehicle should have a larger fuel economy advantage over its gasoline counterpart than a higher performance methanol vehicle (e.g., matching the gasoline vehicle's engine size and gearing). It is possible to trade performance for fuel economy (operating cost).

Fuels with extended lean-burn capabilities show their greatest fuel economy improvement at light load since they permit a reduction in engine throttling. High performance vehicles generally require more engine throttling to obtain the same power as lower performance vehicles. Therefore, high performance methanol, and especially dissociated methanol, vehicles would be expected to show a larger fuel economy improvement over gasoline than would lower performance vehicles. High performance vehicles might be a good early market opportunity for the methanol vehicle manufacturer. This consideration has the potential for hastening the onset of a transition.

Since your study depends on such vagaries as future world economic and political events, as well as technological developments I caution the readers of this final report to remember the context in which the study was conducted and not to draw universal and permanent conclusions from it.

Sincerely,



Joseph G. Finegold, Manager
Fuel Utilization and Systems Engineering

Southern California Edison Company

P. O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

CHARLES B. MC CARTHY
MANAGER OF FUEL SUPPLY

TELEPHONE
(213) 572-2974

TELEX: 674391
CABLE: 674391

March 17, 1983

Dr. Richard P. O'Toole
Jet Propulsion Laboratory
4800 Oak Grove Drive
Mail Stop 506-316
Pasadena, CA 91109

Dear Dr. O'Toole

Subject: California Methanol Assessment

We have appreciated the opportunity to work with JPL and the other study sponsors during the course of the subject study and to review the final report of the California Methanol Assessment. The comments in this letter are the result of a review which was concentrated primarily on stationary applications' findings and conclusions.

In our opinion the report presents a comprehensive analysis of the background, the projections for methanol production, costs, market economics, and use in California. The market and use orientation is especially valuable in highlighting the barriers and problems in the potential transitional periods. We believe that the wide ranging interests and technical competence of the Technical Advisory Group have served well in focusing this study on practical end-use applications of methanol fuel.

The comments on air quality improvement limitations in the "Findings" section of the Executive Summary appear especially relevant. This section confirms our opinion that the potential improvements in air quality resulting from stationary sources would be small compared to vehicular sources.

We would agree with the Report's finding of the lack of competitiveness for electric utility use of methanol compared to pipeline gas in the period to the mid-1990's. The point made concerning feedback effects on methanol production costs in the event of high projected oil prices is also a valid but frequently overlooked factor.

We believe, however, that the report has over-emphasized the utility industry use of methanol in an over-firing mode with natural gas or oil to reduce NO_x. This concept needs a great deal of testing and cost evaluation in a competitive environment with other alternatives before its reasonableness can be accepted. Comments made in the report concerning utility use of methanol for environmental reasons must always be weighed in view of the security of fuel supply sources, reliability of the generating system in operation, and the reasonableness of the costs. This applies whether methanol is used in a dual fuel mode, in gas turbines, or as the single fuel in boilers. The comments made under "Consequences" in the table on "Barriers and Policy Options" in Chapter 9 when viewed in this light may not be entirely accurate.

We understand the logic for the recommendation of possible regulatory encouragement in testing the once-through methanol synthesis concept. However, we believe the demonstration of this concept will add very little to the state-of-the-art of producing methanol or synthesis gas and utilizing them in utility applications.

The consideration of methanol in our fuel planning options and our test programs remains an active issue at Southern California Edison. This study will help focus on future work to be done.

Thank you for the opportunity to work with you and your very professional staff on a comprehensive look at this often mentioned fuel.

Very truly yours,

GEC:scc

cc: R. H. Bridenbecker

X9394

SunTech, Inc.
P.O. Box 1135
Marcus Hook, PA 19061
215-447-1000

March 17, 1983

Mr. Richard P. O'Toole
Methanol Task Manager
California Methanol Assessment
Jet Propulsion Laboratory
4800 Oak Grove Drive
Pasadena, CA 91103

Dear Richard:

I am pleased to have represented Sun Company on the Technical Advisory Group (TAG) for this JPL study to assess methanol as a fuel. I found the TAG reviews interesting and informative and believe the group was effective as a steering committee in helping prepare the final report. Dr. Dave Barmby of Sun's Corporate Technology Group, and a number of my Sun colleagues, worked together to assemble the inputs we provided.

You and your staff are to be complimented for the concerted effort to be objective in this study. The final report now offers a comprehensive assessment and reflects the extensive research by your staff to bring forth pertinent findings.

We at Sun are in accord with most of the report's major findings and conclusions. Nevertheless, several general comments may be appropriate to put into perspective our views on the future of methanol as a fuel:

- The use of methanol as an alternative fuel must be based upon its ability to satisfy market requirements. Although methanol has desirable features, it is premature at the present time to designate it or any other candidate as the best alternative fuel for transportation. The free market will weigh the advantages and disadvantages of methanol and other alternatives to petroleum crude oil as supply changes occur.

- In case of crude oil supply disruptions, as the country goes for energy, so goes California. To the extent that domestic methanol and other alternative transportation fuels can economically displace conventional transportation fuels, they would tend to reduce the importation of crude, and thus reduce the effects of a potential cutoff of imported oil supplies. For the foreseeable future, however, these alternative fuels are not likely to replace imported crude when disruptions occur. Manufacturing capacity does not exist, and will not be built until costs are fully com-

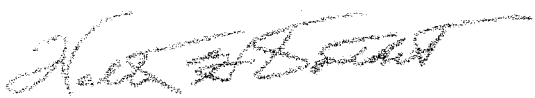
petitive with conventional fuels. Furthermore, it is not in the public, state, or national interest to discriminate arbitrarily and provide incentives for selective alternatives such as domestic ethanol or methanol. In the case of emergency, a reallocation of total available energy supplies would be necessary on a national basis.

- Any realistically projected substitution of methanol for gasoline will have a negligible impact on California air quality, at least through and well beyond the year 2000. The concept itself that a methanol fuel is "cleaner" than a hydrocarbon fuel is debatable since most research has not been done at equivalent performance levels for vehicles fueled with methanol vs. gasoline fueled vehicles. The extent of vehicle emissions control has been determined by set standards and it is to be expected that "neat" methanol vehicles would be designed to meet the same standards as hydrocarbon fueled vehicles.

- There are technologies being developed which may impact any assessment of alternate fuels, including methanol. Some engine developments have been addressed in the report but little has been discussed about new fuels and processes, especially those aimed to providing higher alcohols with methanol/gasoline blends. Such items have been beyond the scope of this particular study because of time constraints, limited funds, and non-commercial aspects. However, these more promising technologies need to be carefully reviewed when recommendations for any future work are being considered.

Again, we congratulate you and your staff at JPL for presenting a timely and useful document about methanol fuel utilization.

Sincerely,



Walter H. Douthit
Staff Engineer
Sun Tech Inc.
Box 1135
Marcus Hook, PA 19061

cc: Dr. D. S. Barmby

United States Synthetic Fuels Corporation
2121 K Street, N.W. Washington, District of Columbia 20586 Telephone: (202) 822-8600

March 24, 1983

Mr. Richard P. O'Toole
Jet Propulsion Laboratory
California Institute of Technology
4800 Oak Grove Drive
Pasadena, California 91109

Dear Mr. O'Toole:

I have quickly reviewed sections of both the summary and technical report that relate particularly to the information and interests of the U.S. Synthetic Fuels Corporation. I was pleased to observe that some of the substantial suggestions offered at the October 1982 sponsors' Technical Advisory Group were reflected in the final draft, and recognize the time and resource limitations that apparently inhibited fuller response to some of those suggestions. The following comments reflect my individual view on the report.

Among the many possible synthetic fuel substitutes for petroleum products, methanol poses special questions and opportunities of interest to the Synthetic Fuels Corporation. On one hand, basic project configurations suggest that methanol may be a lower cost, coal-based liquid fuel compared to gasoline (via the M-gas route) or Fischer-Tropsch liquids. Moreover, some potentially high-valued uses are apparent. On the other hand, large-scale fuel utilization of methanol poses new and complex market issues. The JPL California Methanol Assessment is a usefully broad and structured review of many of the production and utilization issues that affect prospects for a fuel methanol market. I believe the study makes a useful contribution to the methanol literature because it is appropriately broad and structured to consider in an appropriate technical and economic context many of the key issues. However, the same breadth that contributes to the study's usefulness necessarily limits, given time and resource constraints, the depth and definitions of important assessments and discussions. For example, the data sources and discussion of both synthetic fuel production costs and the role of SFC incentives are necessarily limited. Use of the study's information and interpretation of results should be appropriately caveated to reflect these limitations.

In this regard, I would hope that readers moderate the strength of many conclusions, both with respect to the definiteness of facts themselves, as well as interpretation of information. Two examples serve to illustrate my concerns:

(1) In developing comparisons of the cost of various synthetic fuel options, the study necessarily uses available published costs estimates and attempts to normalize estimates produced at different times, in varying levels of detail, and by different sources to a common comparative basis. Even with well-developed project designs, such comparisons require careful engineering analysis that was not possible within the scope of this study. Thus, representations regarding comparative production costs should be viewed in the context of the underlying data sources and analysis, and statements such as "methanol is conclusively more competitive than MTG . . ." (Volume I, pages 4-8) moderated to reflect the depth of analysis actually performed.

(2) The discussion of government production incentives (Volume I, pages 7-11 to 7-13) illustrates similarly and, I believe, inappropriately, definitive interpretation from a limited fact analysis. Quoting this section, ". . . further subsidy may not be necessary for methanol to compete in the octane enhancement market nationally. Thus, SFC could minimize its contribution to coal-to-methanol projects by limiting its participation to loan guarantees." The validity of such an assessment depends on the validity of the underlying production cost and market price assumptions, as well as investor perceptions of risks for these and other key factors.

These comments are not meant to suggest that the underlying analyses and derived relationships and implications in these and other areas are necessarily incorrect. Rather, my concern is that some of the conclusions drawn are rather strong and definitive, relative to the context of the evident underlying analysis.

The discussion of the rationale for a government synthetic fuels program emphasizes production to displace oil imports and the gradual evolution of energy markets. In this context, the discussion of the oil import premium as the major externality motivating government investment incentives is appropriate. However, when one considers the distinct possibility of rapid, non-evolutionary change in the market price or implicit security cost of oil, additional benefits from pioneering synthetic fuel projects become particularly important. Pioneering projects will provide information, learning, and infrastructure development that can yield tangible benefits if it becomes necessary to aggressively expand synthetic fuel production. These benefits from base-building are not closely related to the volume of fuel produced and remain a key rationale for the continuing Energy Security Act program and the SFC implementation strategy. This view of the SFC role and strategy is not fully reflected in the study.

The study is understandably based on fixed evolutionary scenarios. However, as the TAG group observed at the October meeting, many of the expectations regarding methanol market development are driven not by time, but rather by the level of energy prices. Reductions in prices could delay the projected timing for methanol market development, while increases in prices could, perhaps suddenly, accelerate the timing for methanol market change. Thus, the study's statement regarding timing might better be interpreted in the context of the underlying oil price scenarios.

In this regard, the prospect for non-evolutionary change in energy price levels poses key strategic issues for private or governmentally-assisted investments directed toward methanol market evolution. Energy price increases may be needed to make methanol compellingly economic as a fuel. A question for national strategic planning is what, if any, investments need to be made in advance of clear economic competitiveness to allow efficient and aggressive market development if energy price increases made methanol suddenly economic on a large scale. The JPL study develops much useful information bearing on this question, such as the discussion of evolution rates and incremental costs for methanol-compatible gasoline stations. Given the time required to build coal-based methanol production facilities, many transition issues may be manageable, while others may not.

Notwithstanding my concerns regarding the definitiveness, completeness, and presentation of some data, analysis, and conclusions, I think this study is a usefully broad and reasonably comprehensive structuring of information and analysis bearing on prospects for methanol market development in California and nationwide. It is a significant contribution to the methanol literature, and I have been pleased to have the opportunity to comment through the Technical Advisory Group process.

Respectfully,

James K. Harlan,
Manager of Strategic Analysis
Office of Planning